DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

18 CFR Part 35

[Docket No. RM20–16–001; Order No. 881–A]

Managing Transmission Line Ratings

AGENCY: Federal Energy Regulatory Commission, Department of Energy.

ACTION: Order addressing arguments raised on rehearing and clarification.

SUMMARY: The Federal Energy Regulatory Commission (Commission) addresses arguments raised on rehearing and clarifies in part Order No. 881, which revised both the *pro forma* Open Access Transmission Tariff and the Commission's regulations under the Federal Power Act to improve the accuracy and transparency of electric transmission line ratings.

DATES: As of May 25, 2022 the effective date of the document published January 13, 2022 at 87 FR 2244 is confirmed as March 14, 2022.

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SUPPLEMENTARY INFORMATION:

I. Introduction

1. On December 16, 2021, the Federal Energy Regulatory Commission (Commission) issued Order No. 881, a final rule that revised both the *pro forma* Open Access Transmission Tariff (OATT) and the Commission's regulations under the Federal Power Act (FPA) [1] to improve the accuracy and transparency of electric transmission line ratings.[2] Specifically, Order No. 881 requires: public utility transmission providers [3] to implement ambient-adjusted ratings (AAR) [4] on the transmission lines over which they provide transmission service; regional transmission organizations and independent system operators (RTO/ISO) to establish and implement the systems and procedures necessary to allow transmission owners to electronically update transmission line ratings at least hourly; public utility transmission providers to use uniquely determined emergency ratings; public utility transmission owners to share transmission line ratings and transmission line rating methodologies with their respective transmission provider(s) and with market monitors in RTOs/ISOs; and public utility transmission providers to maintain a database of transmission owners' transmission line ratings and transmission line rating methodologies on the transmission provider's Open Access Same-Time Information System (OASIS) site or other password-protected website.

2. On January 18, 2022, several entities filed requests for rehearing and/or clarification of Order No. 881.[5]

3. Pursuant to *Allegheny Defense Project* v. *FERC,* [6] the rehearing requests filed in this proceeding may be deemed denied by operation of law. However, as permitted by section 313(a) of the FPA,[7] we are modifying the discussion in Order No. 881, granting clarification in part, and continue to reach the same result in this proceeding, as discussed below.[8]

II. Discussion

4. In this order, we sustain the result of Order No. 881 and continue to find that, because transmission line ratings and the rules by which they are established are practices that directly affect the cost of wholesale energy, capacity, and ancillary services, as well as the rates for the transmission of electric energy in interstate commerce (hereinafter referred to collectively as ''wholesale rates''), inaccurate transmission line ratings result in Commission-jurisdictional rates that are unjust and unreasonable.[9] Below, we first discuss requests for rehearing and/or clarification related to the AAR requirements that the Commission adopted in Order No. 881, specifically: the requirement for transmission providers to implement AARs on all transmission lines; the impact of the AAR requirements on transmission line relays; the use of AARs 10 days forward in transmission service and operations; seasonal line rating floors; the minimum AAR temperature range and AAR granularity; and solar heating in AAR calculations. Second, we discuss requests for rehearing related to the annual recalculation of seasonal line ratings, as required by Order No. 881. Third, we discuss requests for rehearing and/or clarification related to the transparency requirements that the Commission adopted in Order No. 881, including the data sharing burden, OASIS access, and the role of independent market monitors. Lastly, we address requests for rehearing and/or clarification related to compliance and other miscellaneous issues.

A. AAR-Related Requirements of Order No. 881

1. Requirement for Transmission Providers To Implement AARs on All Transmission Lines

a. Final Rule

5. In Order No. 881, the Commission required transmission providers to apply the AAR requirements set forth in *pro forma* OATT Attachment M, as adopted in the final rule, to all transmission lines,[10] subject to certain exceptions.[11] The Commission adopted

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[1] 16 U.S.C. 824e.

[2] *Managing Transmission Line Ratings,* Order No. 881, 87 FR 2244 (Jan. 13, 2022, 177 FERC ¶ 61,179 (2021).

[3] In this order, we use transmission provider to mean any public utility that owns, operates, or controls facilities used for the transmission of electric energy in interstate commerce. 18 CFR 37.3 (2021). Therefore, unless otherwise noted, ''transmission provider'' refers only to public utility transmission providers. Furthermore, the term ''public utility'' as found in section 201(e) of the FPA means ''any person who owns or operates facilities subject to the jurisdiction of the Commission under this subchapter.'' 16 U.S.C. 824(e).

[4] An ambient-adjusted rating (or AAR) is defined as a transmission line rating that: (1) Applies to a time period of not greater than one hour; (2) reflects an up-to-date forecast of ambient air temperature across the time period to which the rating applies; (3) reflects the absence of solar heating during nighttime periods where the local sunrise/sunset times used to determine daytime and nighttime periods are updated at least monthly, if not more frequently; and (4) is calculated at least each hour, if not more frequently. *See* 18 CFR 35.28(b)(12) (2021); *Pro Forma* OATT attach. M, AAR Definition.

[5] The following entities filed requests for rehearing and/or clarification: American Transmission Company (ATC); Edison Electric Institute (EEI); ITC Holdings Corp., on behalf of its operating subsidiaries, International Transmission Company, Michigan Electric Transmission Company, LLC, ITC Midwest LLC, and ITC Great Plains, LLC (collectively, ITC); MISO Transmission Owners; and Potomac Economics, Ltd., acting in its capacity as MISO's independent market monitor (Potomac Economics).

[6] 964 F.3d 1 (D.C. Cir. 2020) (en banc).

[7] 16 U.S.C. 825*l*(a) (''Until the record in a proceeding shall have been filed in a court of appeals, as provided in subsection (b), the Commission may at any time, upon reasonable notice and in such manner as it shall deem proper, modify or set aside, in whole or in part, any finding or order made or issued by it under the provisions of this chapter.'').

[8] *Allegheny Def. Project,* 964 F.3d at 16–17.

[9] Order No. 881, 177 FERC ¶ 61,179 at PP 3, 29.

[10] *Id.* P 83.

[11] Order No. 881 allows exceptions to the AAR and seasonal line rating requirements in instances where the transmission provider determines, consistent with good utility practice, that the transmission line rating of a transmission line is not affected by ambient air temperatures. *Id.* P 227.

these AAR requirements to improve the accuracy of transmission line ratings, which the Commission explained will cause the rates for the transmission of electric energy in interstate commerce and the sale of electric energy at wholesale in interstate commerce to more accurately reflect the cost of the wholesale service being provided (*i.e.,* energy, capacity, ancillary services, or transmission service), thereby helping to ensure that those wholesale rates are just and reasonable.[12]

6. The Commission chose not to adopt the phased-in implementation schedule proposed in the Notice of Proposed Rulemaking (NOPR) in which a transmission provider would initially implement AARs on only historically congested lines.[13] The Commission reasoned that applying the AAR requirements to all transmission lines would both ensure that wholesale rates remain just and reasonable and strike an appropriate balance between benefits and challenges of AAR implementation. The Commission also found that the record indicated that costs are mostly initial investment costs in energy management system (EMS) improvements to accommodate AARs, implementation of a ratings database, and review (and potentially reset) of protective relays settings and that, once these initial investments are made, adding AARs to additional transmission lines appears to have a minimal incremental cost.[14]

b. Request for Rehearing

7. EEI seeks rehearing of the Commission's decision to require that transmission providers implement AARs on all transmission lines on which they provide transmission service rather than prioritize implementation on historically congested transmission lines as proposed in the NOPR. EEI argues that Order No. 881 fails to support assertions that AARs will ensure that wholesale rates more accurately reflect the cost of wholesale service or that, without AARs, wholesale rates are not just and reasonable.[15]

8. EEI asserts that the Commission's primary rationale for requiring AARs on all transmission lines only supports applying the AAR requirements to congested lines.[16] EEI further asserts that the Commission failed to provide quantified support for applying AARs for near-term service outside RTOs/ISOs and that the examples the Commission relied upon to support its actions, *e.g.,* the potential for avoiding overloads, are hypothetical or anecdotal when applied broadly.[17]

9. EEI also argues that the Commission must weigh the benefits of AARs against the costs that will be incurred by requiring AAR adoption on all transmission lines (subject to a few exceptions). EEI further suggests that Order No. 881 cursorily addresses reliability concerns raised by commenters regarding this requirement without sufficiently explaining why the requirement to impose AARs on all transmission lines addresses those concerns.[18]

10. EEI also argues that the final rule does not reconcile its requirement for AARs on all transmission lines with Order No. 890,[19] which requires transmission providers "to use data and modeling assumptions for the short- and long-term ATC calculations that are consistent with that used for the planning of operations and system planning, respectively, to the maximum extent practicable." EEI contends that the Commission's failure to reconcile Order No. 881 and Order No. 890 reinforces limiting the applicability of the AAR requirements to only congested transmission lines and in real-time operations or day-ahead markets.[20]

11. Finally, EEI contends that, while the exceptions to the AAR requirements are needed, they highlight why AARs should not be required on all transmission lines. For example, EEI states that Order No. 881 allows the "temporary use of a transmission line rating different than would otherwise be required under *pro forma* OATT Attachment M [if it] is necessary to ensure safety and reliability." [21] EEI argues that "reliable operation should not be addressed by exception" and that transmission owners and transmission providers "should be allowed the flexibility to implement AARs in a reliable manner on the specific circuits where congestion/transfer capability benefits are derived." [22]

c. Commission Determination

12. Having considered EEI's request for rehearing on this matter, we continue to find that requiring transmission providers to apply the AAR requirements set forth in *pro forma* OATT Attachment M to all transmission lines on which they provide transmission service, subject to certain exceptions, is just and reasonable.

13. First, in response to EEI's statement that "the Commission assumes, without support, that AARs will ensure that wholesale rates more accurately reflect the cost of the wholesale service being provided," [23] we disagree. In Order No. 881, to conclude that the AAR requirements will ensure that wholesale rates are just and reasonable, the Commission relied on the "inextricabl[e] link[ ]" between transmission line ratings and wholesale rates.[24] That inextricable link reflects the basic economics of the transmission system; that is, the relationship between the physical system and economic fundamentals, a relationship described in detail by the Commission.[25] Consistent with those economics, the Commission explained how inaccurate transmission line ratings—both the understating of transmission capability and the overstating of transmission capability—can affect congestion and resulting wholesale rates.[26] These economic fundamentals apply to all transmission lines, not only those that have historically been congested. The Commission explained the benefit of applying the AAR requirements to all transmission lines particularly "[g]iven the difficulty in predicting unexpected congestion before it happens." [27] Changes in the transmission flow will arise due to short-term and long-term changes in the physical transmission system (*e.g.,* outages and transmission line upgrades),[28] due to changes to the location and amount of generation and load, or due to unexpected events, such as extreme weather. Because such

[12] *Id.* P 83.

[13] *Id.* P 84. The Commission had proposed to define a historically congested transmission line as "a transmission line that was congested at any time in the five years prior to the effective date of [this final rule]." *Managing Transmission Line Ratings,* 85 FR 6420 (Jan. 21, 2021), 173 FERC ¶ 61,165, at P 92 (2020) (NOPR.)

[14] Order No. 881, 177 FERC ¶ 61,179 at P 85.

[15] EEI Request for Rehearing at 4.

[16] *Id.* at 5.

[17] *Id.*

[18] *Id.* (citing Order No. 881, 177 FERC ¶ 61,179 at PP 128–133).

[19] *Preventing Undue Discrimination and Preference in Transmission Service,* Order No. 890, 72 FR 12266 (Mar. 15, 2007), 118 FERC ¶ 61,119, *order on reh'g,* Order No. 890–A, 73 FR 2984 (Jan. 16, 2008), 121 FERC ¶ 61,297 (2007), *order on reh'g,* Order No. 890–B, 123 FERC ¶ 61,299 (2008), *order on reh'g,* Order No. 890–C, 74 FR 12540 (Mar. 25, 2009), 126 FERC ¶ 61,228, *order on clarification,* Order No. 890–D, 129 FERC ¶ 61,126 (2009).

[20] EEI Request for Rehearing at 6 (quoting Order No. 890, 118 FERC ¶ 61,119 at P 292).

[21] *Id.* at 6–7 (citing Order No. 881, 177 FERC ¶ 61,179 at P 232).

[22] *Id.*

[23] *Id.* at 4.

[24] Order No. 881, 177 FERC ¶ 61,179 at P 30.

[25] *Id.*

[26] *Id.* PP 34–35.

[27] *Id.* P 94.

[28] *Id.* (stating "the AAR requirements adopted in this final rule are beneficial in mitigating the impact of transient congestion, *i.e.,* temporary or short-term congestion that does not occur on a regular basis, such as congestion caused by unexpected equipment outages or other unusual conditions.").

changes may affect all transmission lines, the economic logic underlying the AAR requirements applies to all transmission lines. By establishing and relying on the basic economic logic underlying the relationship between more accurate transmission line ratings and wholesale rates,[29] the Commission had ample support to conclude that applying the AAR requirements to all transmission lines will lead to just and reasonable wholesale rates.[30]

14. As for the decision to apply the AAR requirements to all transmission lines, EEI is correct that the Commission must weigh the benefits against the burdens of applying the AAR requirements to all transmission lines. The Commission did just that. As explained in Order No. 881, the incremental cost to implement AARs on additional transmission lines—beyond those that are historically congested—once the initial costs have been incurred, is minimal.[31] EEI does not dispute this fact. By contrast, as the Commission explained in Order No. 881, extending the AAR requirements to apply to those additional transmission lines is expected to have significant value. As the Commission explained in Order No. 881 and we reiterate here, we expect that, over time, the additional congestion costs that will be alleviated through AAR implementation on all transmission lines (compared to only on historically congested transmission lines) will exceed the additional, primarily one-time, costs to implement AARs on those additional transmission lines.[32]

15. As the Commission explained in Order No. 881, AARs can help alleviate congestion costs. While the greatest initial benefit may come from implementing AARs on historically congested transmission lines, limiting implementation to such lines, would likely fail to alleviate considerable congestion costs. Generally, patterns of congestion across different transmission lines are difficult to predict. This difficulty is particularly notable during unanticipated system events, such as sudden forced outages and extreme weather, when flows may change considerably from normal operations. During such events, any increased transfer capability provided through AARs may prove valuable even on transmission lines that have not been historically congested.[33]

16. Additionally, AAR implementation itself will affect congestion patterns, as changes to transmission line ratings may change generation dispatch patterns and, by extension, congestion patterns.[34] Moreover, as the generation mix continues to evolve and new generation comes online in new locations, congestion patterns will also evolve.[35] By design, limiting AARs to only historically congested transmission lines would not address evolving transmission congestion patterns until after potentially costly congestion occurs on previously uncongested lines. For the above reasons, applying the AAR requirements to only historically congested transmission lines would not strike the right balance between the benefits and burdens of AAR implementation.

17. Indeed, the Commission provided the example in Order No. 881 of congestion costs during extreme events as compared to potential congestion cost savings due to AAR implementation. During certain single extreme events, the congestion cost savings of AAR implementation would have been substantial enough from that event alone to justify applying the AAR requirements to all transmission lines, instead of just to historically congested transmission lines. For example, in the February 2021 cold weather event, MISO, which primarily implements seasonal and static line ratings, experienced unprecedented east-to-west flows throughout its service footprint and accrued $773 million in congestion charges in just a few days, significantly in congestion patterns that were neither predicted nor typical in MISO.[36]

18. With respect to EEI's claim that the Commission provided inadequate support for applying the AAR requirements for near-term transmission service outside RTOs/ISOs,[37] we disagree. As explained above, Order No. 881 established a clear linkage between transmission line ratings and wholesale rates.[38] The Commission's reasoning applies equally in both RTOs/ISOs and non-RTO/ISO regions. While EEI criticizes the Commission's support for its determination as ''largely hypothetical,'' we note that EEI offers no additional arguments or evidence on rehearing that suggests the Commission's use of basic economic theory to support its conclusions was not reasonable.[39] Moreover, despite EEI's characterization of the supporting evidence as ''anecdotal'' and lacking ''quantified support,'' the Commission based its conclusions on substantial evidence in the record that transmission line ratings, *not transmission line ratings in RTOs/ISOs,* are practices that directly affect wholesale rates.[40]

19. We also disagree with EEI's assertion that Order No. 881 was arbitrary and capricious because it addressed reliability concerns in only a ''cursory manner,'' and that it provided for reliability ''by exception.'' [41] In Order No. 881, the Commission adopted the System Reliability section of *pro forma* OATT Attachment M, which permits a transmission provider to use a temporary alternate rating (in place of what would be otherwise required in Attachment M) if the transmission provider reasonably determines such an alternate rating is necessary to ensure the safety and reliability of the transmission system.[42] Contrary to arguments from EEI, the Commission carefully considered the impacts of the AAR requirements and established the necessary mechanisms to provide transmission owners with the flexibility to ensure safety and reliability.[43] While EEI may have preferred that the Commission adopt a more limited application of the AAR requirements, nothing in its rehearing request suggests

[29] *Sacramento Mun. Util. Dist.* v. *FERC,* 616 F.3d 520, 531 (D.C. Cir. 2010) (recognizing that it is ''perfectly legitimate for the Commission to base its findings . . . on basic economic theory''); *Assoc. Gas Distributors* v. *FERC,* 824 F.2d 981, 1008 (D.C. Cir. 1987) (''Agencies do not need to conduct experiments in order to rely on the prediction that an unsupported stone will fall.'').

[30] Order No. 881, 177 FERC ¶ 61,179 at P 29.

[31] *Id.* P 85 (citing Exelon Corporation (Exelon) Comments at 8; Indicated PJM Transmission Owner Comments at 5–6; AEP Post-Technical Conference Comments at 2–3; September 2019 Technical Conference, Day 1 Tr. at 181:4–9).

[32] *Id.* PP 93–95.

[33] *Id.* P 95.

[34] *Id.*

[35] *See, e.g.,* American Clean Power Association (ACPA) and Solar Energy Industries Association (SEIA) Joint Comments at 8, 11; Electric Power Supply Association (EPSA) Comments at 4; New England State Agencies Comments at 6.

[36] Order No. 881, 177 FERC ¶ 61,179 at P 95; Organization of MISO States, Inc. (OMS) Comments at 10; OMS Reply Comments at 7; *see* FERC, NERC and Regional Entity Staff Report, *The February 2021 Cold Weather Outages in Texas and the South Central United States* (Nov. 16, 2021), *https://www.ferc.gov/media/february-2021-cold-weather-outages-texas-and-south-central-united-states-ferc-nerc-and.*

[37] EEI Request for Rehearing at 5.

[38] Order No. 881, 177 FERC ¶ 61,179 at PP 29–34.

[39] *See supra* note 31.

[40] Order No. 881, 177 FERC ¶ 61,179 at P 31 (citing AEP Comments at 3; Ohio FEA Comments at 6; New England State Agencies Comments at 8; OMS Comments at 6; Potomac Economics Comments at 5; CAISO DMM Comments at 4; SPP MMU Comments at 1–2; R Street Institute Comments at 2; Industrial Customer Organizations Comments at 11–12; TAPS Comments at 5–6; WATT Comments at 3–5; Certain TDU Comments at 4–5; Clean Energy Parties Comments at 2–3; EDFR Comments at 3).

[41] EEI Request for Rehearing at 5–6.

[42] Order No. 881, 177 FERC ¶ 61,179 at P 228.

[43] *Id.*

that Attachment M is insufficient to protect safety and reliability.

20. In making its determination in Order No. 881, the Commission relied on the record to find that accounting for ambient air temperatures in transmission line ratings can result ''in significant *reliability,* operational, and economic benefits'' by, for example, increasing transmission line ratings and thereby affording transmission providers more options to manage load.[44] AARs correct existing occasional overestimations of transmission line ratings during periods when the actual ambient air temperature is greater than the temperature assumed when the rating was calculated.[45] As a result, implementation of AARs will lower transmission line ratings when extreme high temperature events occur, reducing the likelihood of inadvertently overloading a transmission line.[46] Moreover, consistent with PJM's and Potomac Economics' post-technical conference comments, the Commission explained that, because AARs typically increase transmission line ratings when actual temperatures are lower than long-term assumptions, the resulting increased transmission capability will provide operators additional flexibility during many hours, which promotes reliability.[47] Specifically, by increasing the ATC, system operators would have more options available to manage congestion, and potentially ameliorate system conditions during an emergency. This is consistent with the 2019 FERC and North American Electric Reliability Corporation (NERC) Staff Report on the January 2018 South Central cold weather event, which recommended adoption of transmission line ratings that better consider ambient temperature conditions.[48]

21. Finally, we disagree with EEI's contention that Order No. 881 failed to reconcile the requirements outlined in *pro forma* OATT Attachment M with the provisions adopted in Order No. 890[49] that require transmission providers ''to use data and modeling assumptions for the short- and long-term ATC calculations that are consistent with that used for the planning of operations and system planning, respectively, to the maximum extent practicable.''[50] In Order No. 881, the Commission acknowledged that AARs used in near-term operations will deviate from those transmission line ratings used in various planning functions.[51] However, Order No. 890 found that requirements for consistency would ''remedy the potential for undue discrimination by eliminating discretion and ensuring comparability in the manner in which a transmission provider operates and plans its system to serve *native load* and the manner in which it calculates ATC for service to *third parties.*''[52] Since Order No. 881 imposes requirements to change the calculation of ATC by all transmission providers on all transmission lines, any resulting deviation between near-term ATC calculations and those used in modeling assumptions for various ''planning of operation and system expansion'' does not create the potential for undue discrimination and therefore does not conflict with the requirements of Order No. 890. In any event, we note that the requirement in Order No. 890 for consistent assumptions was ''to the maximum extent practicable,'' and clarify that none of the requirements in Order No. 881 require revisions to the assumptions used in the transmission planning and development contexts.[53]

2. Transmission Line Relays

a. Final Rule

22. In Order No. 881, when discussing its decision to apply the AAR requirements to all transmission lines, the Commission noted that ''any facility can become the most limiting element as the transmission system changes, and in certain circumstances flows may change considerably from normal operations.''[54] The Commission further noted that Reliability Standard PRC–023–4 requires setting transmission line relays at values at or above 115% to 170% of various maximum values for current or power carrying capability, *e.g.,* 115% of the highest seasonal 15-minute facility rating of a circuit or 150% of the highest seasonal four-hour Facility Rating of a circuit.[55]

b. Request for Clarification

23. EEI requests clarification that compliance with the AAR requirements of Order No. 881 will require all transmission owners and transmission providers to evaluate or reevaluate all their transmission protective relay settings to ensure these new worst-case transmission line ratings will not limit transmission loadability under Reliability Standard PRC–023–4 and, wherever necessary, develop and apply new protective relay settings.[56] Specifically, EEI explains that the AAR requirements adopted in Order No. 881 are beyond PJM's current practice, despite the Commission's reliance on PJM as an example, and will require companies to conduct considerable analysis of new maximum transmission line ratings. According to EEI, that analysis of new maximum transmission line ratings, in turn, will require companies to evaluate or reevaluate all of their transmission protective relay settings to ensure compliance with Reliability Standard PRC–023–4.[57]

c. Commission Determination

24. We clarify two aspects of the AAR requirements related to transmission providers' transmission protection relay settings. First, if a transmission provider establishes higher transmission line ratings, it will have to evaluate or reevaluate its applicable protection systems for that facility. Second, we clarify that in a majority of situations the relay setting should exceed AAR values.

25. As an initial matter, we disagree with EEI that Order No. 881 requires transmission providers to evaluate or reevaluate ''*all* transmission protective relay settings to ensure worse case line ratings will not limit transmission loadability under Reliability Standard PRC–023–4.''[58] Rather, because compliance with Reliability Standard PRC–023–4 is only applicable to a subset of protection systems, *i.e.,* phase protection systems,[59] not all transmission protection relay settings will be implicated by the requirements adopted in Order No. 881. Additionally, some transmission line ratings will qualify for an exception to the AAR

[44] *Id.* P 85 (emphasis added).

[45] *Id.* P 35.

[46] *Id.;* NOPR, 173 FERC ¶ 61,165 at P 106; Exelon Post-Technical Conference Comments at 9.

[47] *See* PJM Post-Technical Conference Comments at 2; Potomac Economics Post-Technical Conference Comments at 8.

[48] 2019 FERC and NERC Staff Report, *The South Central United States Cold Weather Bulk Electric System Event of January 17, 2018,* at 96–97 (July 2019) (2019 FERC and NERC Staff Report), *https://www.ferc.gov/sites/default/files/2020-05/07-18-19-ferc-nerc-report_0.pdf.*

[49] Order No. 890, 118 FERC ¶ 61,119.

[50] EEI Request for Rehearing at 6 (citing Order No. 890, 118 FERC ¶ 61,119 at P 292).

[51] Order No. 881, 177 FERC ¶ 61,179 at P 131.

[52] Order No. 890, 118 FERC ¶ 61,119 at P 292 (emphasis added).

[53] *Id.* P 347.

[54] Order No. 881, 177 FERC ¶ 61,179 at P 48.

[55] *Id.* P 99.

[56] EEI Request for Rehearing at 12–13.

[57] *Id.*

[58] *Id.* at 13 (emphasis added).

[59] NERC Reliability Standard PRC–023–4 only applies to transmission owners, generator owners, and distribution providers, with load-responsive phase protection systems as described in Attachment A of the Reliability Standard, for certain transmission lines and transformers (*i.e.,* those with low-voltage terminals operated or connected at 200 kV and above and between 100 kV and 200 kV as identified by the planning coordinator as critical to the reliability of the bulk electric system (BES)). Reliability Standard PRC–023–4, at 1–2, *https://www.nerc.com/pa/Stand/Reliability%20Standards/PRC-023-4.pdf.*

requirements,[60] and some transmission lines may already have implemented the AAR requirements.[61] Finally, some transmission providers have already calculated and implemented AARs for the range of local historical temperatures (over the entire period for which records are available) plus-or-minus a margin of 10 degrees Fahrenheit,[62] and thus already have relay settings evaluated or reevaluated for compliance with Order No. 881.

26. That said, outside the circumstances identified above, we clarify that, if, as a result of favorable ambient conditions, a transmission provider establishes a higher transfer capability than the currently determined maximum facility ratings, the transmission provider must evaluate its applicable protection systems for that facility in order to comply with Reliability Standard PRC–023–4 and prevent protection settings from limiting transmission loadability. In those instances, some relay settings might require changes to maintain reliability and to accommodate the additional power transfer capability based on AARs. However, relays are set to operate during abnormal conditions such as fault conditions that result in currents that are many factors higher than the maximum continuous facility rating, without limiting power/current flow under any system configuration or interfering with system operators' ability to take remedial action to protect system reliability and thus are not expected to conflict with AARs. As the Commission explained in Order No. 881, relays are set based on practical limitations (*e.g.,* 115% of the highest seasonal 15-minute Facility Rating of a circuit or 150% of the highest seasonal four-hour Facility Rating of a circuit).[63] While 115% of the highest seasonal 15-minute Facility Rating of a circuit or 150% of the highest seasonal four-hour Facility Rating of a circuit defines minimum relay settings, because relays are set to detect abnormal conditions such as fault currents that are many factors higher than the maximum rating of the facility and include a margin to account for minor system changes, transmission providers generally set relay settings above the minimum requirement. Therefore, relay settings should already exceed the minimum requirements even when accounting for new AAR values and thus, in those circumstances, should not merit new protection settings. However, we note that, in Order No. 881, the Commission inadvertently stated that relay settings ''in the majority of cases should not exceed AAR values.'' [64] We clarify that this was in error. On the contrary, relay settings in the majority of cases should exceed AAR values, meaning, as explained above, that the requirements adopted in Order No. 881 will only require new protective settings of existing relay settings where the transmission line rating increases on compliance with the final rule and that increase results in the relay setting dropping below the minimum required by Reliability Standard PRC–023–4.[65]

3. Use of AARs 10-Days Forward in Transmission Service and Operations

a. Final Rule

27. In Order No. 881, the Commission required transmission providers to use AARs as the relevant transmission line rating for transmission service that starts or ends within 10 days of the date of the request, for the curtailment or interruption of point-to-point transmission service anticipated to occur (start and end) within the next 10 days, and for the curtailment of network transmission service or secondary service or redispatch network transmission service or secondary transmission service anticipated to occur (start and end) within 10 days.[66] The Commission justified this requirement based on:

(1) the additional benefits gained by adopting a threshold that permits weekly point-to-point transmission service requests to be evaluated using AARs; (2) the additional benefits gained by the use of daytime/nighttime ratings . . . within the 10-day threshold; (3) the adequate accuracy of ambient air temperature forecasts combined with the ability to implement appropriate forecast margins to alleviate operational concerns associated with persistently decreasing real-time transmission line ratings; and (4) the low relative cost difference between a shorter forward threshold and the proposed 10-day threshold.[67]

b. Request for Rehearing

28. MISO Transmission Owners contend that the Commission ignored or failed to meaningfully respond to MISO Transmission Owners' arguments that requiring the use of AARs for a 10-day forward period could adversely impact reliability and request rehearing on this point.

29. MISO Transmission Owners argue that transmission system reliability could be jeopardized in situations where actual ambient air temperatures are higher than forecast and that, as forecasts approach 10 days, the accuracy of forecasts decreases, which in turn increases the uncertainty and accompanying risk. Specifically, MISO Transmission Owners contend that, due to the imprecise nature of weather forecasting, requiring the use of AARs for a 10-day forward period will result in RTOs/ISOs granting near-term transmission service based on inaccurate calculations of transfer capability, resulting in less accurate calculations of ATC.[68] For support, MISO Transmission Owners cite evidence from the American Meteorological Society website on the accuracy of medium range forecasts.[69] Finally, MISO Transmission Owners suggest that, by adopting this provision, the Commission ''fail[ed] the requirements of reasoned decision-making.'' [70] They contend that, when coupled with the 10-degree temperature margin requirement and the hourly AAR update requirement, this provision will be burdensome, requiring transmission owners to develop millions of data points and ratings across their systems and incorporate voluminous data into all of their market and transmission processes.[71]

c. Commission Determination

30. We sustain the determination in Order No. 881 to require the use of AARs for a 10-day forward period. As the Commission acknowledged in Order No. 881, relying on ambient air temperature forecasts necessitates

[60] Order No. 881, 177 FERC ¶ 61,179 at PP 227–228.

[61] We note that, while Order No. 881 requires more AAR calculations than are currently implemented in the PJM look-up tables, there remains the possibility that many of the transmission owners may have calculated transmission line ratings, and calibrated relay settings accordingly, for a wider range of ambient air temperatures. For example, Entergy calculates AARs for every degree of temperature change. *See* September 2019 Technical Conference, Docket No. AD19–15, Day One Tr. 157:7–15 (filed Oct. 8, 2019) (September 2019 Technical Conference, Day 1 Tr.).

[62] As described in Order No. 881, transmission facilities in this case includes overhead conductors and other transmission equipment. Specifically, the Commission defined a transmission line rating in the *pro forma* OATT Attachment M as ''the maximum transfer capability of a transmission line, computed in accordance with a written transmission line rating methodology and consistent with good utility practice, considering the technical limitations on conductors and relevant transmission equipment (such as thermal flow limits), as well as technical limitations of the transmission system (such as system voltage and stability limits). Relevant transmission equipment may include, but is not limited to, circuit breakers, line traps, and transformers.'' Order No. 881, 177 FERC ¶ 61,179 at P 44.

[63] *Id.* P 99.

[64] *Id.*

[65] *Id.*

[66] *Id.* P 104.

[67] *Id.* P 121.

[68] MISO Transmission Owners Request for Rehearing at 15–16.

[69] *Id.* at 17 & n.53.

[70] *Id.* at 13–14.

[71] *Id.* at 13.

accepting some degree of forecast error; however, we disagree that this error will jeopardize system reliability. First, recognizing that ambient air temperature forecast error exists, the Commission required in Order No. 881 that, no matter how accurate the forecast temperatures that underlie transmission providers' calculations of AARs, transmission providers must implement forecast margins to ensure sufficient confidence that actual temperatures will not be greater than the forecast temperatures.[72] Next, the Commission further established that transmission providers should re-evaluate and adjust such forecast margins if they turn out to be insufficiently or overly conservative.[73] Finally, we disagree that the potential error in temperature estimates is significant. A published analysis of the National Oceanic and Atmospheric Administration (NOAA) National Blend of Models (NBM) forecast—one of the publicly available NOAA forecasts that looks out at least 10 days—indicates that the mean absolute error for 240 hour (10 day) forward continental United States surface temperature forecasts was approximately four to six degrees Fahrenheit in July to November 2016.[74]

31. Because transmission providers must implement forecast margins, we disagree with MISO Transmission Owners that inaccurate ambient air temperature forecasts will create reliability concerns. Specifically, by incorporating forecast margins and reevaluating overly conservative forecast margins into their AAR calculations, transmission providers will account for any such forecast inaccuracies in a manner necessary to maintain system reliability. Thus, because transmission providers must use forecast margins that will account for potential inaccurate forecasts, inaccurate forecasts will *not,* as MISO Transmission Owners suggest, cause excessive real-time service curtailments. Indeed, the Commission found in Order No. 881—and we reiterate here—that although transmission providers will continue to curtail transmission at times due to unrealized ambient air temperature assumptions (just as they do today), the need for such curtailments should be *decreased* as a result of the new AAR requirements.[75]

32. Moreover, as the Commission acknowledged in Order No. 881, next day and further forward transmission scheduling already rely heavily upon weather forecasts to inform next-day load and intermittent generation availability.[76] Transmission providers have the tools to manage any congestion or potential reliability events that could arise from errors in weather forecasts. These include the ability to curtail or interrupt point-to-point transmission service under sections 13.6 and 14.7 of the *pro forma* OATT, the ability to curtail network service under section 33 of the *pro forma* OATT, and the ability to redispatch network service under sections 30.5 and 33 of the *pro forma* OATT.

33. We also disagree with MISO Transmission Owners' argument that the 10-day threshold for AARs is unduly burdensome. As the Commission found in Order No. 881, and we continue to find here, the cost associated with requiring AARs for additional days forward is essentially the cost of accessing, storing, and processing the additional forecast data, and the cost of calculating, storing, and incorporating into transmission service the additional hours of AARs.[77] As this process will likely be largely automated, we do not anticipate that the cost and implementation burden of the 10-day threshold, as opposed to a shorter threshold, will be significantly higher.[78] Additionally, we reiterate that, for RTOs/ISOs, the 10-day threshold applies only to the movement of electricity into/out of their service territories, which is generally point-to-point transmission service. As stated in Order No. 881, because energy transactions in RTOs/ISOs take place within the real-time and day-ahead markets, the 10-day threshold will provide very little additional benefits within existing RTO/ISO markets. Accordingly, Order No. 881 stated that the 10-day threshold does not apply to internal transactions or internal flows associated with through-and-out transactions in RTOs/ISOs.[79] Instead, the 10-day threshold requirement applies only to RTOs/ISOs' evaluation or determination of availability of transmission service at the seams of RTO/ISO service territories.[80]

34. Turning to MISO Transmission Owners' citation to information on the American Meteorological Society website about the accuracy of forecasts beyond eight days,[81] we reject the introduction of such new evidence as out of time.[82] In any event, we find such evidence unpersuasive. First, we note that the statement regarding the accuracy of medium range forecasts cited by MISO Transmission Owners was approved by the American Meteorological Association in 2015. As the Commission noted in Order No. 881, one type of forecast that transmission providers might use to comply with the AAR requirement is the NBM forecast provided by NOAA.[83] The NBM forecast did not even exist in 2015, and has gone through at least four complete iterations since its introduction in 2016 (from Version 1.0 to Version 4.0).[84] The Commission noted in Order No. 881 the tendency for weather forecast accuracy to steadily improve.[85] As such, statements about weather forecast accuracy from 2015 are likely to under-report accuracy of forecasts in 2025 (when implementation of AARs is required). Furthermore, the Commission in Order No. 881 found that available data on 10-day ambient air temperature forecast accuracy indicated that such forecasts were not so inaccurate that they cannot provide any benefits when used as part of AARs, even when adjusted with appropriate forecast margins.[86] Indeed, the Commission found that the reported levels of error would likely allow for a meaningful number of hours in any season where a 10-day forward AAR would provide benefits relative to the seasonal line rating.[87]

35. The Commission also noted that the adoption of a 10-day forward AAR provided other benefits, beyond any direct benefits of additional transmission line capacity due to ambient air temperature considerations. Specifically, the Commission found that the adopted 10-day threshold would permit weekly point-to-point transmission service requests to be evaluated using AARs, and would provide additional benefits in forward nighttime hours where the newly required AARs would consider the lack of solar heating in those hours.[88] We continue to find that these additional benefits will accrue, even in the unlikely event that the use of AARs 10 days forward results in no hours where daytime AARs are greater than seasonal line ratings.

72 Order No. 881, 177 FERC ¶ 61,179 at P 126.

73 *Id.* PP 127–128.

74 *Id.* PP 122–123.

75 *Id.* P 127.

76 *Id.* P 129.

77 *Id.* P 125.

78 *Id.*

79 *Id.* P 134.

80 *Id.; see also id.* P 106.

81 MISO Transmission Owners Request for Rehearing at 17 n.53.

82 *See* 18 CFR 385.713(c) (2021).

83 Order No. 881, 177 FERC ¶ 61,179 at P 123.

84 *See NOAA, National Blend of Models—NBM Versions, https://vlab.noaa.gov/web/mdl/nbm-versions* (last visited April 21, 2022).

85 Order No. 881, 177 FERC ¶ 61,179 at P 122.

86 *Id.* P 123.

87 *Id.*

88 *Id.* PP 121–122.

4. Seasonal Line Rating Floors

a. Final Rule

36. In Order No. 881, the Commission declined to require the use of a transmission line rating ''floor'' whereby no AAR would fall below the lowest seasonal line rating. In doing so, the Commission reasoned that, while seasonal line ratings are generally already calculated to reflect worst-case weather conditions, to the extent that a transmission provider experiences extreme temperatures that exceed seasonal assumptions, the resulting transmission line ratings will be more accurate than seasonal line ratings and will send important price signals to market participants. The Commission concluded that, in such circumstances, transmission providers should be able to plan for such extreme temperatures given current temperature forecasting capabilities.[89]

b. Request for Clarification

37. MISO Transmission Owners request that the Commission clarify that individual transmission owners and transmission providers may use a seasonal line rating ''floor'' (which would ensure that no AAR falls below the lowest seasonal line rating) if they reasonably determine, consistent with good utility practice, that use of such a floor is appropriate.[90] ITC makes a similar request and, to the extent the Commission denies clarification on this point, ITC seeks rehearing.[91]

38. MISO Transmission Owners contend that many transmission owners have developed seasonal line ratings using a combination of assumptions that include ambient air temperature, wind speed, and other variables, that take into consideration the relationship between them as each variable changes. MISO Transmission Owners further suggest that this is contrary to the Commission's suggestion that transmission owners use ''worst case'' assumptions in their transmission line ratings. MISO Transmission Owners argue that denying transmission owners the ability to use a floor when justified would compel transmission owners to use ratings that are inconsistent with their planning criteria.[92]

39. ITC states that its transmission line ratings do not represent worst-case conditions but rather use a combination of assumptions that include ambient air temperature, wind speed, wind direction, and solar irradiation and that their transmission line ratings take into consideration the relationship between the variables as each variable changes. ITC suggests that implementation of AARs across the range of historically observed temperatures, plus-or-minus a 10-degree margin, presumes less risk, which could cause divergence in the transmission line ratings used for planning and operational purposes. ITC contends that allowing for the use of a seasonal line ratings floor would help mitigate operational risk and reliability planning risk, which should be of paramount importance given how infrequently AARs are likely to exceed the long-term planning assumptions used to establish the lowest seasonal line rating.[93]

c. Commission Determination

40. We deny the requested clarification and rehearing on this issue. In Order No. 881, the Commission adopted the AAR requirements in order to ensure that transmission line ratings are more accurate and, therefore, that wholesale rates are just and reasonable.[94] In contrast, imposing a seasonal line rating floor would fail to produce transmission line ratings that reflect the actual capabilities of the transmission lines. A transmission line rating limited by a seasonal line rating floor could result in wholesale rates that do not accurately reflect costs and could result in overloaded conductors or equipment. We recognize that not imposing a seasonal line rating floor means that there will be times in which transmission line ratings fall below the seasonal line rating, for example, because extreme weather events may result in ambient air temperatures above even those used to calculate the seasonal line ratings. However, in such situations, the lower AARs as required by this rule would be the more accurate ratings. The transmission line ratings resulting from a seasonal line rating floor would be inaccurate and thus would not reflect true system limitations and could create reliability concerns.

5. Minimum AAR Temperature Range and AAR Granularity

a. Final Rule

41. In Order No. 881, the Commission required that any methods used to determine AARs be valid for at least the range of local historical temperatures (over the entire period for which records are available) plus-or-minus a margin of 10 degrees Fahrenheit (10-degree margin requirement). The Commission further required that, where a transmission provider uses pre-calculated AARs within a look-up table or similar database, such values must be calculated for all temperatures within such a valid range. Similarly, where a transmission provider uses a formula or computer program to calculate AARs based on forecasted temperatures, such a formula/program must be accurate across such a valid range. The Commission also required transmission providers to have procedures in place to handle a situation where forecast temperatures fall outside of the valid range of temperatures, to ensure that safe and reliable transmission line ratings are used. The Commission required transmission providers to revise their look-up tables or similar databases or formulas/programs in the event that actual temperatures set new high or low records to maintain the 10-degree Fahrenheit margin.[95]

42. The Commission, in Order No. 881, also required transmission providers to implement AARs that update at least with every five-degree Fahrenheit increment of temperature change (five-degree requirement), in order to meet the *pro forma* OATT Attachment M requirement that an AAR reflect an up-to-date forecast of ambient air temperature. The Commission explained that greater temperature increments might introduce inaccuracies into transmission line ratings, resulting in wholesale rates that are unjust and unreasonable, and that a minimum amount of AAR temperature granularity is necessary to ensure that transmission line ratings sufficiently reflect changes in ambient air temperatures.[96]

b. Request for Rehearing

43. MISO Transmission Owners contend that the Commission failed to satisfy its burden of supporting the five-degree requirement as just and reasonable and request rehearing on this point. MISO Transmission Owners state that the specific use of five-degree Fahrenheit increments was not discussed or proposed in the NOPR, which inhibited parties' opportunity to comment.[97]

44. MISO Transmission Owners contend that the Commission's only evidentiary support for the five-degree requirement is that the Electric Reliability Council of Texas (ERCOT) uses this increment. According to MISO

[89] *Id.* P 125.

[90] MISO Transmission Owners Request for Rehearing at 18.

[91] ITC Request for Rehearing at 3 n.4, 11.

[92] MISO Transmission Owners Request for Rehearing at 18–19.

[93] ITC Request for Rehearing at 10.

[94] Order No. 881, 177 FERC ¶ 61,179 at P 83.

[95] *Id.* P 185.

[96] *Id.* P 187.

[97] MISO Transmission Owners Request for Rehearing at 11.

Transmission Owners, the Commission fails to demonstrate how this provision might be appropriate in a multi-state region like MISO.[98] MISO Transmission Owners also argue that the Commission supplied no evidence to support its conclusion that transmission line rating increments of greater than five degrees might introduce inaccuracies into transmission line ratings, resulting in wholesale rates that are unjust and unreasonable.[99]

45. MISO Transmission Owners further contend that the Commission failed to take into account the compliance burdens that the five-degree requirement will impose, especially when coupled with the 10-degree margin requirement and the requirement to update AARs hourly for every hour over the course of a rolling 10-day period.[100] EEI claims that requiring entities to use a five-degree Fahrenheit temperature increment will be a significant and costly effort that will not yield improvements to the ATC of affected transmission lines.[101] ITC asserts that the extensive increase in the volume of transmission line ratings calculations required by Order No. 881 was not contemplated in the NOPR[102] and requests that the Commission provide transmission owners and transmission providers greater flexibility regarding the implementation of additional data points to support AAR calculations.[103] MISO Transmission Owners and ITC contend that, at least partially due to the plus-or-minus 10-degree range and five degree maximum increment requirements, transmission owners will be required to develop or maintain millions of data points and transmission line ratings across their systems.[104] ITC further argues that the Commission has not shown that the benefits of maintaining these records or the potential use of this data will outweigh the associated burdens.[105] MISO Transmission Owners and ITC contend that, by failing to take this balancing into account, the Commission's decision to impose this requirement fails to constitute reasoned decision-making.[106]

46. MISO Transmission Owners also argue that, because the Commission acknowledged in Order No. 881 that the mean absolute error for continental United States surface temperature forecasts was approximately four to six degrees Fahrenheit in July to November of 2016,[107] it belies any Commission conclusion that the use of five-degree increments, which are within this margin of error, is just and reasonable. MISO Transmission Owners suggest that this demonstrates that the use of a five-degree increment is likely to produce inaccurate ATC determinations and that Order No. 881 is internally inconsistent and contrary to the record.[108]

47. EEI contends that Order No. 881 fails to consider the significant weather differences between various regions of the country and lacks substantial evidence to support the five-degree requirement when slightly larger increments would have no meaningful impact on ratings of affected transmission lines.[109] EEI therefore requests that the Commission allow flexibility for governing entities to determine what temperature increments might work best in their region.[110] Similarly, MISO Transmission Owners argue that, if the Commission determines that a temperature increment is necessary, the Commission should allow transmission owners and transmission providers to work collaboratively to develop appropriate temperature increments for AARs that are tailored to their regions, climates, and transmission systems, consistent with good utility practice and reasonable deference to engineering judgment.[111]

c. Commission Determination

48. On rehearing, MISO Transmission Owners, EEI, and ITC argue that the Commission failed to support the five-degree requirement, to appropriately balance the burdens of the five-degree requirement (particularly combined with other requirements adopted in the final rule) with the benefits, and to consider the considerable weather differences across the country. For the reasons explained below, we disagree. We continue to find that the five-degree requirement is just and reasonable and will result in more accurate transmission line ratings, and, in turn, just and reasonable wholesale rates, by ensuring that AARs reflect up-to-date forecasts of ambient air temperatures.

49. As an initial matter, in Order No. 881, the Commission reasoned that remedying inaccurate transmission line ratings requires a minimum amount of AAR temperature granularity.[112] We disagree that the Commission failed to adequately support its finding that five degrees is the appropriate increment for such granularity. In its comments, Vistra Corp. (Vistra) argued that absent some guidance on the maximum increment of ambient air temperature change beyond which AARs must be updated, a transmission provider would be able to use temperature increments so large that it would undermine the Commission's AAR requirement.[113] The Commission agreed, explaining that, absent guidance, some implementations of AARs may not result in an AAR change despite substantial changes in forecasted temperature and therefore could not be considered an ''up-to-date forecast of ambient air temperature.''[114]

50. Having established that a minimum amount of temperature granularity was needed for the AAR requirements adopted in Order No. 881 to yield just and reasonable wholesale rates, the Commission took the step of establishing a five-degree Fahrenheit maximum increment—the five-degree requirement.[115] The Commission reasoned that an increment greater than five degrees might introduce inaccuracies into transmission line ratings that would result in wholesale rates that are unjust and unreasonable.[116] The Commission also found that the five-degree requirement was a necessary corollary of the requirement that an AAR reflect an *up-to-date* forecast of ambient air temperature.[117]

51. Contrary to the claim that the Commission reached this conclusion without evidence—or based only on the example of ERCOT—the Commission considered, as reference points, a range of AAR implementation examples, including PJM, ERCOT, and Entergy Services, LLC (Entergy). PJM provides updated AARs every nine degrees Fahrenheit;[118] ERCOT provides updated AARs every five degrees Fahrenheit;[119] and Entergy calculates AARs for every one degree Fahrenheit of temperature change.[120] Based on this

[98] *Id.* at 12.

[99] *Id.* at 13.

[100] *Id.*

[101] EEI Request for Rehearing at 11.

[102] ITC Request for Rehearing at 6.

[103] *Id.* at 7.

[104] *Id.* at 8; MISO Transmission Owners Request for Rehearing at 13.

[105] ITC Request for Rehearing at 8.

[106] *Id.;* MISO Transmission Owners Request for Rehearing at 14.

[107] MISO Transmission Owners Request for Rehearing at 14 (citing Order No. 881, 177 FERC ¶ 61,179 at P 123).

[108] *Id.*

[109] EEI Request for Rehearing at 11.

[110] *Id.* at 11–12.

[111] MISO Transmission Owners Request for Rehearing at 14–15.

[112] Order No. 881, 177 FERC ¶ 61,179 at P 187.

[113] Vistra Comments at 6.

[114] Order No. 881, 177 FERC ¶ 61,179 at P 187.

[115] *Id.*

[116] *Id.*

[117] *Id.*

[118] *Id.* P 138.

[119] *Id.* P 187.

[120] September 2019 Technical Conference, Day One Tr. at 157:7–15.

record evidence, the Commission adopted a requirement that balances the need for accuracy, and the benefits thereof, with the burdens imposed by a more onerous requirement, such as the one Entergy voluntarily uses for its own AAR calculations. MISO Transmission Owners are correct that, in adopting the five-degree requirement, the Commission partially based its finding on ERCOT's experience. But the Commission did so with good reason: ERCOT has successfully implemented AARs since 2005,[121] and attests to have benefited considerably from its AAR implementation, which specifically includes the five-degree increment.[122] We are not persuaded by MISO Transmission Owners' claim that because ERCOT is a single-state transmission operator, the Commission inappropriately relied on ERCOT's practices to support imposing requirements on RTOs such as MISO. It is unclear what relevance the number of states within a transmission provider's territory has on the probative value of its experience implementing AARs. To the extent the argument is related to the range of potential temperatures experienced within a transmission provider's territory, and whether that should justify different AAR requirements, we address similar assertions below.

52. In addition to basing its findings on actual AAR implementation by several transmission providers, the Commission relied on statistics describing the value of transmission line rating changes with each degree of temperature change. Specifically, the record from the September 2019 technical conference demonstrates that the difference in transmission line rating accuracy between the five-degree requirement adopted in the final rule and larger temperature increments, *e.g.,* PJM's nine-degree increment, is meaningful. A change in temperature of 1 degree Celsius (1.8 degrees Fahrenheit) can change transmission capacity by 1%.[123] Given the sensitivity of wholesale rates to changes in transmission line ratings, as the Commission explained in Order No. 881,[124] we believe that even a 1% increase in transmission capacity could present considerable savings for ratepayers. In other words, the Commission had substantial evidence to support the five-degree requirement, both from transmission providers' experience implementing AARs and statistics on the value of additional accuracy of transmission line ratings.

53. The Commission balanced the evidence of the benefits of this granularity in AAR calculations with the burdens imposed by increasing precision. Specifically, the Commission considered record evidence that AAR implementation will likely be primarily automated and that implementation costs will primarily be one-time expenses.[125]

54. We acknowledge that the AAR requirements, including the five-degree requirement, will impose implementation costs on every transmission provider, including those that already implement AARs. But we sustain the Commission's finding that the benefits of the requirements adopted in Order No. 881, on balance, outweigh the burdens. For those transmission providers that already implement AARs, we note that they will be required to revise their transmission line rating look-up tables or similar databases to implement AARs as required by Order No. 881 (including expanding the range of temperatures included in such look-up tables or similar databases to at least the range of local historical temperatures plus-or-minus a margin of 10 degrees Fahrenheit), regardless of whether their temperature increment is five degrees or another increment. In other words, we find that the burden of requiring a five-degree temperature increment versus the burden of requiring a larger than five-degree temperature increment is likely minimal.

55. In response to MISO Transmission Owners' and ITC's contention that the five-degree requirement, particularly when combined with the 10-degree temperature margin requirement, imposes an undue data reporting burden, we disagree. These requirements will materially affect the size of the *look-up tables or similar databases* from which transmission line ratings will be looked-up each hour (for transmission providers that voluntarily use such look-up tables or similar databases), but such requirements will not have any effect on the amount of data that must be stored in the *line ratings database* under the adopted recordkeeping requirements. This is because, as discussed further below, we expect the total data storage in such look-up tables or similar databases to remain small, that transmission line ratings, once recalculated to comply with Order No. 881, will change only infrequently, the expectation that implementation will be automated, and that there is no requirement for transmission providers to implement look-up tables at all. Specifically, with respect to the effect on the size of the look-up tables or similar databases, we expect that the five-degree requirement and the 10-degree margin requirement may increase by three to five times the amount of data in such databases/tables for some transmission providers that currently use look-up tables or similar databases with narrow temperature ranges or large temperature step-sizes, but that such databases/tables will nonetheless continue to store a very small amount of data,[126] and that for any particular transmission line such data would usually remain unchanged for months or years. Given that computers will mainly generate and interact with such look-up tables or similar databases, the burden associated with any such increase in the amount of data is not significant. Furthermore, we reiterate that there is no requirement that transmission providers implement such look-up tables or similar databases *at all.* Transmission providers are free to implement formulas or computer programs that will compute line ratings, rather than implementing a line ratings approach that requires looking-up ratings from a database/table.[127]

56. As for arguments for regional flexibility, we are not persuaded that significant weather differences across the country justify the use of different temperature increments for calculating AARs in different regions. The Commission adopted the five-degree requirement as a minimum accuracy threshold that the Commission believes—and we sustain—is necessary to ensure just and reasonable wholesale

[121] *Id.* at 79:6–10.

[122] *Id.* at 80:9–19.

[123] *See id.* at 52:4–9 (Hudson Gilmer, Line Vision, Inc.) (The benefit of AARs is generally "1% additional capacity for each degree Celsius of reduced temperature below the static assumption."); September 2019 Technical Conference, Speaker Comments—Jake Gentle (Forecasts for Dynamic Line Rating), Docket No. AD19–15–000, at slide 14 (Sept. 10, 2019).

[124] Order No. 881, 177 FERC ¶ 61,179 at PP 30, 34, 35.

[125] *See* Order No. 881, 177 FERC ¶ 61,179 at PP 94, 125; September 2019 Technical Conference, Day One Tr. at 154:25–157:15; September 2019 Technical Conference, Day One Tr. at 142:14–18; September 2019 Technical Conference, Day Two Tr. at 295:4–7.

[126] For example, for a transmission line for which the range of historically observed local temperatures was −25 to +115 degrees Fahrenheit, and which had four types of ratings (one normal and three emergency ratings), a look-up table or similar database would need to contain at least 264 data points for each transmission line (33 data points for each of the four rating types, computed for both daytime and nighttime). For comparison, PJM's current transmission line rating database computes 64 data points for each transmission line (eight data points for each of four data types, computed for both daytime and nighttime). PJM Ratings Information, *https://www.pjm.com/markets-and-operations/etools/oasis/system-information/ratings-information.*

[127] Order No. 881, 177 FERC ¶ 61,179 at P 185.

rates. While we agree that certain transmission provider regions, such as MISO's, cover a large geographic area and may experience considerable temperature differences as compared to other regions, it is unclear why these differences should merit different transmission line rating accuracy requirements. In other words, we have no reason to conclude that a larger or smaller geographic footprint or wider or narrower range of temperatures across a year justify treating transmission providers disparately with regard to the AAR requirements.

57. We also disagree with MISO Transmission Owners' suggestion that the NOPR gave commenters inadequate notice of the final rule's five-degree requirement. In the NOPR, the Commission proposed AAR requirements that would ensure that transmission line ratings ''reflect an up-to-date forecast of ambient temperature,'' [128] which reasonably includes consideration of what minimum degree of granularity might be required to meet this standard.

58. As explained above, different transmission providers that have voluntarily implemented AARs use look-up tables or similar databases with different temperature increments as a means of ensuring the AARs reflect an up-to-date forecast of ambient temperature. In response to the NOPR, Vistra argued that, absent some guidance on the maximum increment of ambient air temperature change beyond which AARs must be updated, a transmission provider would be able to use temperature increments so large as to undermine the effectiveness of the Commission's AAR requirements.[129] In Order No. 881, the Commission refined its proposal based on stakeholder comments, which is the very purpose of the notice and comment requirements under the Administrative Procedures Act.[130] The courts have made clear that an ''agency 'is not required to adopt a final rule that is identical to the proposed rule.' On the contrary, '[a]gencies are free—indeed, they are encouraged—to modify proposed rules as a result of the comments they receive.' '' [131] That is exactly what the Commission did. The fact that commenters in response to the NOPR raised this issue and asked the Commission to address it reinforces this fact.

59. As for MISO Transmission Owners' contention that the mean absolute error of 10-day temperature forecasts being approximately four to six degrees suggests that the five-degree requirement is inappropriate, we find no merit to the argument. The mean absolute error of a particular forecast and the maximum temperature increment for updating AARs are wholly separate concepts. The mean absolute error of a forecast represents the historical average difference between forecasted value and actual value. By contrast, the maximum temperature increment for updating AARs represents the maximum temperature degree change which might occur before necessitating different AAR values. As such, we find that no inaccuracies or internal inconsistencies are introduced if a maximum temperature increment is smaller than a forecast's mean absolute error.

60. We also further clarify the relationship between the five-degree granularity requirement and the requirement to recalculate AARs hourly. In Order No. 881, the Commission responded to Vistra's comments discussed above that, absent certain minimum requirements for the method to calculate AARs hourly, the Commission's AAR requirements could be undermined. To address this concern, the Commission clarified that ''a transmission provider must implement AARs that update at least with every five-degree Fahrenheit increment of temperature change, in order to meet the *pro forma* OATT Attachment M requirement that an AAR reflect an up-to-date forecast of ambient air temperature,'' [132] which is the five-degree granularity requirement. The five-degree granularity requirement does not affect the required timing of a transmission provider's recalculation of AARs. We reiterate that a transmission provider must recalculate AARs at least every hour.[133] When the transmission provider undertakes that hourly calculation, it must do so using a method that incorporates the five-degree granularity requirement. That method may be based on a formula or a look-up table or similar database which contains pre-calculated AARs as a function of temperature (*e.g.,* from –10 to 110 degrees Fahrenheit). To the extent a transmission provider uses the latter method such look-up table or similar database must have no more than five degrees between temperature ''steps.''

6. Solar Heating in AAR Calculations

a. Final Rule

61. Order No. 881 requires transmission providers to incorporate solar heating into AARs by implementing separate AARs for daytime and nighttime periods.[134] It further requires transmission providers to update the sunrise and sunset times used to calculate their AARs at least monthly, if not more frequently.[135] The Commission found that this requirement will produce benefits in forward nighttime hours that would not be realized if the AAR requirements were imposed over a timeframe shorter than 10 days forward and that the accuracy benefits that result from applying daytime/nighttime ratings to weekly point-to-point transmission service and to shorter duration transmission service up to 10 days forward are significant.[136]

b. Requests for Rehearing

62. Both EEI and ITC request rehearing on the daytime/nighttime ratings requirement and argue that this requirement constitutes a substantial departure from the proposal contained in the NOPR. EEI asserts that the scope of benefits that flow from this daytime/nighttime ratings requirement is unclear, particularly given that transmission providers will still rely on industry standards to maintain compliance.[137] ITC adds that the Commission did not demonstrate that any potential market efficiencies that flow from this and other requirements outweigh the burden on transmission owners to gather the significant amount of data required to calculate AARs for the average system.[138]

c. Commission Determination

63. We sustain the result of Order No. 881 regarding the Commission's requirement that transmission providers incorporate solar heating into AARs by implementing separate AARs for daytime and nighttime periods, and to update the sunrise and sunset times used to calculate their AARs at least monthly, if not more frequently (daytime/nighttime ratings requirement).

64. In Order No. 881, the Commission required implementation of daytime/nighttime ratings based on evidence in the record that such a requirement

[128] NOPR, 173 FERC ¶ 61,165 at P 3 n.3.

[129] Vistra Comments at 6–7.

[130] 5 U.S.C. 553.

[131] *Earthworks* v. *U.S. Dept. of the Interior,* 496 F. Supp. 3d 472, 498–99 (D.D.C. 2020) (quoting *Ne. Md. Waste Disposal Auth.* v. *EPA,* 358 F.3d 936, 951 (D.C. Cir. 2004) (per curiam)); *see also id.* (citing *Int'l Union, United Mine Workers of Am.* v. *Mine Safety & Health Admin.,* 407 F.3d 1250, 1259 (D.C. Cir. 2005)) (''Public input is, after all, one of the purposes of the APA's notice-and-comment scheme.'').

[132] Order No. 881, 177 FERC ¶ 61,179 at P 187.

[133] *Id.* PP 47, 162.

[134] *Id.* P 147.

[135] *Id.* P 149.

[136] *Id.* P 122.

[137] EEI Request for Rehearing at 10.

[138] ITC Request for Rehearing at 5.

would enhance the accuracy of transmission line ratings, and therefore result in just and reasonable wholesale rates.[139] None of the arguments contained in the requests for rehearing persuade us to alter that view.

65. In response to the NOPR, several commenters supported incorporating predictable daytime/nighttime ratings into AARs.[140] As the Commission explained in Order No. 881, solar heating is an important input consideration for calculating thermal transmission line ratings.[141] By removing solar heating assumptions from transmission line ratings during nighttime periods, transmission providers increase the accuracy of transmission line ratings and thereby enable wholesale rates to better reflect the true cost to serve load. According to several commenters, incorporating daytime/nighttime ratings, subject to the exceptions adopted in Order No. 881,[142] will provide important increases in transfer capability. This, in turn, will lower wholesale rates. Specifically, commenters explained that daytime/nighttime ratings would, on average, increase nighttime transfer capability by anywhere from 5% to 14%.[143] Potomac Economics found that such transfer capability increase would decrease wholesale rates in MISO by approximately $30 million per year.[144] Importantly, such increases in transfer capability due to calculating transmission line ratings for nighttime periods can support operators during potentially challenging intervals, such as before sunrise during the morning ramp or after sunset during the evening ramp. Contrary to EEI's assertions, this evidence demonstrates the significant economic benefits of the daytime/nighttime ratings requirement.

66. Further, we continue to find that the daytime/nighttime requirement can yield these benefits at minimal cost,[145] contrary to ITC's contention. Incorporating daytime/nighttime ratings into AAR calculations can be done at minimal costs, as explained by several commenters.[146] As noted earlier, we expect the costs to implement daytime/nighttime ratings to primarily be one-time automation costs. Once automated, we do not expect the addition of daytime/nighttime ratings to materially increase the cost and complexity of implementing the AAR requirements.

67. Finally, we disagree that stakeholders lacked adequate notice. In the NOPR, the Commission noted that AARs could incorporate other forecasted inputs and, as an example, pointed to PJM's implementation of ''day and night ambient air temperature tables, where the night ambient air temperature table assumes zero solar irradiance.'' [147] Further, the Commission sought comment on whether to require the implementation of dynamic line ratings,[148] which the Commission expressly defined as a transmission line rating that reflects inputs including solar irradiance forecasts and of which daytime/nighttime ratings are the most basic and obvious example.[149] Moreover, the objective of the NOPR—and the final rule—was to improve the accuracy of transmission line ratings, with solar irradiance forecasts repeatedly discussed as one tool for doing so, including multiple mentions of PJM's use of daytime/nighttime AARs.[150] Finally, several commenters in response to the NOPR either noted the benefits of, or voiced support for, incorporating predictable daytime/nighttime solar irradiance forecasts into AARs.[151]

B. Seasonal Line Ratings—Annual Recalculation Requirement

1. Final Rule

68. In Order No. 881, the Commission required that seasonal line ratings be calculated at least annually, if not more frequently.[152] While the NOPR proposed requiring seasonal line ratings to be updated on a monthly basis, the final rule revised that requirement in response to stakeholder comments. Specifically, the Commission acknowledged that calculating monthly updates to seasonal line ratings would be burdensome and that the weather assumptions underlying seasonal line ratings are unlikely to change on a month-to-month basis.[153]

2. Request for Rehearing

69. ITC seeks rehearing of the annual update requirement for seasonal line ratings; it requests greater flexibility for transmission owners and transmission providers to update seasonal line ratings as warranted, consistent with good utility practice.[154] ITC asserts that it used recognized industry technical standards to support a multi-year study of its transmission system, which included the collection and analysis of a number of different data sets related to weather, temperature, conductor parameters, and historical inputs, among other things. ITC contends that its use of a multi-year study increases the accuracy of seasonal line ratings and meets the intent of Order No. 881.[155]

70. ITC also claims that there is no technical or market-driven justification to require ITC to update its seasonal line ratings annually. Rather, ITC contends that, given its reliance on its multi-year study, it would not be possible for ITC to update its seasonal line ratings annually and that this provision would result in a continuous weather study operation that would be burdensome and unnecessary. Finally, because transmission planning processes partially rely on seasonal line ratings, ITC asserts that changing these ratings on an annual basis would unnecessarily inject complexity and uncertainty into the multi-year transmission planning processes.[156]

3. Commission Determination

71. Regarding ITC's request for rehearing on the annual update requirement for seasonal line ratings, we sustain the result in Order No. 881. We disagree with ITC that there is no justification for the annual update requirement for seasonal line ratings. On the contrary, transmission system conditions, including relevant climate and weather data, are frequently changing, especially as extreme weather events are increasing in frequency and duration.[157] To the extent that a

[139] For example, the Commission cited to comments from R Street Institute, Pacific Gas and Electric (PG&E), Indicated PJM Transmission Owners, Dominion Energy Services, Inc. (Dominion), Potomac Economics, and Vistra. Order No. 881, 177 FERC ¶ 61,179 at PP 147–48.

[140] R Street Institute Comments at 3; PG&E Comments at 11–12; Indicated PJM Transmission Owner Comments at 8–9; Dominion Comments at 8; Potomac Economics Comments at 14–15; Vistra Comments at 4–5.

[141] Order No. 881, 177 FERC ¶ 61,179 at PP 147–149; PG&E Comments at 11–12; Vistra Comments at 4–5; Potomac Economics Comments at 15.

[142] Order No. 881, 177 FERC ¶ 61,179 at PP 227–28.

[143] PG&E Comments at 11; Entergy Comments at 8; Potomac Economics Comments at 15.

[144] Potomac Economics Comments at 15.

[145] Order No. 881, 177 FERC ¶ 61,179 at P 148.

[146] Potomac Economics Comments at 15; Vistra Comments at 4–5.

[147] Order No. 881, 177 FERC ¶ 61,179 at P 144 (citing NOPR, 173 FERC ¶ 61,165 at P 23).

[148] NOPR, 173 FERC ¶ 61,165 at P 100.

[149] *Id.* P 5 n.5.

[150] *Id.* P 23 n.40.

[151] *See, e.g., Small Refiner Lead Phase-Down Task Force* v. *EPA,* 705 F.2d 506, 549 (D.C. Cir. 1983) (finding that a final provision is permitted if an entity participating in a rulemaking ''ex ante, should have anticipated that such a requirement might be imposed.'').

[152] Order No. 881, 177 FERC ¶ 61,179 at P 215.

[153] *Id.*

[154] ITC Request for Rehearing at 9.

[155] *Id.*

[156] *Id.*

[157] Order No. 881, 177 FERC ¶ 61,179 at P 215 (citing ACPA/SEIA Comments at 8, 11; EPSA Comments at 4; New England State Agencies Comments at 6); NOAA, National Centers for Environmental Information, *U.S. Billion-Dollar Weather and Climate Disasters* (2021), *https://www.ncdc.noaa.gov/billions/;* Quadrennial Energy Review, *Transforming the Nation's Electricity*

transmission provider continues to implement seasonal line ratings for years without reviewing and updating those ratings, transmission system conditions are likely to have changed to such a degree as to render the ratings inaccurate and associated wholesale rates unjust and unreasonable. As the Commission stated in Order No. 881, seasonal line ratings, once established, should be reviewed when equipment changes are made, climate or weather data necessitates, or when otherwise prudent.[158] While the Commission proposed in the NOPR to require such recalculations on a monthly basis, the Commission concluded in Order No. 881 that an annual update requirement for seasonal line ratings strikes an appropriate balance between ensuring accurate seasonal line ratings as weather patterns continue to change and the costs associated with updating such transmission line ratings on a regular basis.[159] We continue to believe that the Commission struck the proper balance.

72. Nevertheless, we clarify that the Commission did not prescribe the procedure for recalculating seasonal line ratings, including determining which inputs have changed in a year. For instance, a transmission provider could comply with the annual update requirement for seasonal line ratings by recalculating its seasonal line ratings annually to adjust seasonable temperature assumptions, but then also perform a more detailed recalculation every few years using multi-year temperature data to consider temperature patterns that are harder to identify with only a single year of new temperature data.

73. Moreover, we clarify that the requirement to engage in an annual recalculation does not require transmission owners to undertake unnecessary change from year to year. To the extent that relevant inputs have not changed from one year to the next, the annual recalculation may simply result in continuing to use transmission owner's existing facility ratings.

C. Transparency

1. Data Sharing Burden

a. Final Rule

74. In Order No. 881, the Commission required each transmission provider to maintain a database of its transmission line ratings and methodologies on the transmission provider's OASIS site or other password-protected website.[160] The Commission required that this database be in such a form that can be accessed by all parties with OASIS access or access to the password-protected website. The Commission stated that the database should archive and allow for querying of all current transmission line ratings and all transmission line ratings used in the past five years.[161]

75. The Commission further required that transmission line ratings stored in the required database must include a full record of all transmission line ratings, both as used in real-time operations, and as used for all future market periods for which transmission service is offered.[162] The Commission provided a specific example of the implications of the final rule for data storage requirements. Further, while the Commission did not require implementation of DLRs when issuing Order No. 881, it noted that if a transmission provider implements DLRs on any of its transmission lines, then under this requirement it would document the DLRs on such transmission lines in the same way that it documents its AARs. The Commission noted that transmission providers may determine that a variety of approaches to storing this data may be acceptable as long as users of the database can readily identify which such ratings (including for the operational hour and any forward hours) were in effect for which transmission lines at which times.[163] The Commission did not specify exactly how records of seasonal or static line ratings should be stored in the transmission line rating database. However, the Commission explained that such longer-term transmission line ratings do not necessarily need to be stored on an hourly basis, so long as users of the database can readily identify which ratings were in effect for which transmission lines at which times. The Commission noted that some transmission lines may not have any AARs at all, where permitted under *pro forma* OATT Attachment M, and so may only have ratings such as seasonal or static line ratings.[164]

b. Requests for Rehearing

76. EEI and ITC request rehearing of the data requirements of Order No. 881. EEI argues that the Commission erred in requiring transmission owners to store in the required database a full record of all transmission line ratings, both as used in real-time operations and as used for all future market periods for which transmission service is offered, without a showing of substantial need.[165] ITC similarly asserts that the Commission erred by requiring transmission owners to comply with unduly burdensome data storage and maintenance requirements.[166]

77. EEI and ITC allege that the data requirements impose a significant burden on transmission owners for which the Commission has failed to articulate corresponding and substantially greater benefits.[167] EEI reports that one member utility estimates that it will send several million transmission line ratings per hour to its transmission provider.[168] ITC calculates that implementing Order No. 881's requirements on its own transmission system would result in 3.4 million ratings calculated and stored every hour and that the total number of ratings calculated and stored would ''quickly become astronomical.'' [169] EEI notes that even its member utilities who have been using AARs for years do not maintain the kind of data required by Order No. 881.[170] Rather, EEI states that member utilities using AARs commonly embed algorithms into the transmission owner's EMS that allow power flow analyses to make use of AAR curves for each circuit. EEI also contends that the volume of data required is a significant departure from the NOPR and significantly more burdensome.[171] EEI alleges that ''[t]he requirements in the Final Rule are significantly more burdensome than providing data upon request'' and that the Commission's decision to impose such requirements is ''arbitrary and capricious.'' [172]

c. Commission Determination

78. In response to requests for rehearing regarding the data storage and sharing requirements of Order No. 881, we continue to find that the benefits outweigh the burdens and that these requirements will help ensure just and reasonable wholesale rates. As the Commission found in Order No. 881, making transmission line ratings and methodologies available to a broader range of stakeholders will amplify the expected benefits of the proposal included in the NOPR, further facilitate more accurate transmission line ratings,

System: The Second Installment of the QER, at 4–2 (Jan. 2017).

[158] Order No. 881, 177 FERC ¶ 61,179 at P 215; MISO Comments at 21.

[159] Order No. 881, 177 FERC ¶ 61,179 at P 215.

[160] *Id.* P 330.

[161] *Id.*

[162] *Id.* P 339.

[163] *Id.* P 339 n.819.

[164] *Id.* P 339 n.820.

[165] EEI Request for Rehearing at 3.

[166] ITC Request for Rehearing at 5.

[167] *Id.* at 8; EEI Request for Rehearing at 10.

[168] EEI Request for Rehearing at 9–10.

[169] ITC Request for Rehearing at 8.

[170] EEI Request for Rehearing at 10–11.

[171] *Id.* at 9–11.

[172] *Id.* at 11.

and facilitate more cost-effective decisions by market participants and state agencies.[173] For example, these requirements will help potential interconnection customers more easily identify optimal interconnection locations and understand or reproduce congestion analyses.[174] These requirements will also enable transmission customers to better understand what is driving the prices that they are required to pay.[175] In addition, as noted in Order No. 881,[176] transparency with transmission line ratings and methodologies will be particularly beneficial to wholesale market participants trying to manage uncertainty. With respect to FTR market participants, for example, because FTR payouts are based on congestion costs that change with transmission line ratings, sharing transmission line ratings and methodologies with a wider range of stakeholders will help establish efficient FTR market price discovery by improving FTR market participants' understanding of certain drivers of congestion, and allow such market participants to build such understanding into their FTR bids and offers.[177] Commenters also suggest that these requirements may assist transmission providers in considering public policy driven transmission needs as part of their regional transmission planning processes.[178] We reiterate the Commission's finding in Order No. 881 that the benefits of increased transparency, such as those just described, are likely to outweigh the burden on transmission providers.[179]

79. We also find that these requirements reasonably follow from the NOPR, which proposed to require transmission owners to share transmission line ratings for each period for which transmission line ratings are calculated and emphasized the value of such transparency to verify the resulting transmission line ratings and to identify potential errors.[180] The NOPR then explicitly sought comment on ''whether to require transmission owners to make their transmission line ratings and rating methodologies available to other interested stakeholders, including posting information on their OASIS pages or other password protected online forum.'' [181] Commenters extensively discussed the benefits and burdens of the proposed transparency requirements, including responding to this request for comment.[182] In addition to the explicit language in the NOPR, storing transmission line ratings and methodologies on OASIS or a similar website should be an expected means of achieving the data-sharing contemplated by the NOPR. In fact, the Commission has similarly required the use of OASIS or a similar website to ensure transparency in other contexts.[183]

80. Further, we continue to find that Order No. 881's requirements follow from existing regulations surrounding transmission line rating data sharing and retention. As noted in Order No. 881,[184] the requirement that transmission providers must archive the data for five years of history follows reasonably from the Commission's regulations for document retention periods that apply to OASIS postings.[185] In addition, as noted in Order No. 881,[186] § 37.6 of the Commission's regulations already requires transmission providers, upon customer request, to make all data used to calculate ATC for any constrained posted path publicly available on OASIS. This includes the limiting elements and the cause of the limit (*e.g.,* thermal, voltage, stability), as well as load forecast assumptions.[187] Similarly, § 37.7of the Commission's regulations also requires historical data to be available for 90 days or, upon request, five years. We note again that the durations for document retention in Order No. 881 are consistent with these existing requirements.

81. Finally, we also find unpersuasive arguments that the transparency requirements are unduly burdensome. In response to comments that the total number of transmission line ratings required to be stored would ''quickly become astronomical,'' [188] we find the implementation and operation of a database of this type to be well within the normal business scope of a data-intensive entity like a transmission provider. For example, the 3.4 million transmission line rating records that ITC explains it would have to calculate and store every hour would total only about 1.8 terabytes over the entire five-year line rating retention period required in Order No. 881,[189] although the overall storage requirements would be several times that, considering memory for back-ups and data management. As a pure matter of quantity of data stored (*i.e.,* ''hard drive size''), this is a de minimis amount of storage. We note that ITC might be arguing that this is a significant number of *individual records* to store, even if they require a small data storage footprint. While we recognize that there will be significant numbers of line rating records, we have also explained that we expect that transmission providers will use automated processes to calculate these line ratings,[190] and we similarly expect that transmission providers will use automated processes to populate the ratings databases. As such, we disagree that the storage of the line rating data will have a meaningful burden.

2. OASIS Access

a. Final Rule

82. In Order No. 881, the Commission required each transmission provider to maintain a database of its transmission owners' transmission line ratings and methodologies on the password-protected section of the transmission provider's OASIS site or other

[173] Order No. 881, 177 FERC ¶ 61,179 at P 336.

[174] *See, e.g.,* ACPA/SEIA Comments at 18–20.

[175] *See, e.g.,* TAPS Comments at 24.

[176] Order No. 881, 177 FERC ¶ 61,179 at P 337.

[177] DC Energy Comments at 3. While different RTOs/ISOs have different names for these financial products, such as financial transmission rights, transmission congestion rights, congestion revenue rights, etc., for simplicity here we will use FTRs to refer to any such financial product in the RTOs/ISOs.

[178] *See, e.g.,* New England State Agencies Comments at 20.

[179] Order No. 881, 177 FERC ¶ 61,179 at P 336.

[180] NOPR, 173 FERC ¶ 61,165 at PP 125–130.

[181] *Id.* P 129.

[182] *See* Order No. 881, 177 FERC ¶ 61,179 at PP 316–320, 336–340 (summarizing relevant comments).

[183] *See, e.g., Reform of Generator Interconnection Procedures and Agreements,* Order No. 845, 83 FR 21342 (May 9, 2018), 163 FERC ¶ 61,043 at PP 236–238 (2018), *errata notice,* 167 FERC ¶ 61,123, *order on reh'g,* Order No. 845–A, 84 FR 8156 (Mar. 6, 2019), 166 FERC ¶ 61,137 (2019), *errata notice,* 167 FERC ¶ 61,124, *order on reh'g,* Order No. 845–B, 168 FERC ¶ 61,092 (2019).

[184] Order No. 881, 177 FERC ¶ 61,179 at P 340.

[185] 18 CFR 37.7 (2021) (Information to be posted on the OASIS).

[186] Order No. 881, 177 FERC ¶ 61,179 at P 338.

[187] *See* 18 CFR 37.6 (2021).

[188] ITC Request for Rehearing at 8.

[189] We estimated this storage space requirement based on the following assumptions: First, we assume that the 3.4 million hourly line ratings reflect each of the 240 forecasted line ratings for each of the relevant transmission lines and transmission line rating types (normal and emergency), as required by Order No. 881. Second, we assume the rating records are stored in a table with each row having line ID, rating day and hour, rating type, 240 forecast ratings and 240 forecast hours, and 2 extra variable character columns in case of other information requirements. Thereby, the 3.4 million hourly line ratings is reduced to 14,167 hourly records (that is, (3.4 million hourly line ratings)/(240 forecasted ratings)). The hourly storage requirements are then estimated to be 41 megabytes/hour. That is, (2,998 bytes per row) * (14,167 rows/hour)/(1,048,576 bytes/megabyte). We estimate the bytes per row to be 2,998 bytes as follows: (8 bytes for line ID) + (8 bytes for rating day and hour) + (2 bytes for rating type) + (4 bytes per forecast rating * 240 forecast ratings) + (8 bytes per forecast rating hour * 240 forecast hours) + (50 bytes each for the 2 variable character columns). The entire five years of transmission line ratings data that are required to be stored is then calculated as (41 megabytes/hour) * (24 hours/day) * (365 days/year) * (5 years)/(1,000,000 megabytes/terabyte) = 1.8 terabytes.

[190] Order No. 881, 177 FERC ¶ 61,179 at PP 125, 149, 163, 169, 362.

password-protected website. The Commission found that allowing other entities (beyond transmission providers and market monitors) to access the password-protected section of the transmission provider's OASIS site or other password-protected website containing the database of transmission line ratings and methodologies will further facilitate more accurate transmission line ratings and more cost-effective decisions by market participants.[191]

b. Request for Clarification

83. EEI requests that the Commission clarify that those seeking to access the data on their OASIS site be required to show a ''business need'' for the information.[192] EEI further suggests that the requirements in Order No. 881 might not be sufficient to maintain confidentiality.[193] EEI characterizes the requirements of Order No. 881 as mandating that transmission owners share information on their transmission line rating methodology with market participants that may not have signed non-disclosure agreements, which EEI claims significantly deviates from past practice and infringes on the rights of transmission providers to rate their own equipment. EEI requests that the Commission clarify that the transmission owner may limit access to those with a business need and may require execution of non-disclosure agreements prior to accessing the information.[194]

84. EEI also requests that the Commission clarify that the data might be subject to protections for Critical Energy Infrastructure Information (CEII). EEI claims that the use of AARs will, in many instances, establish the maximum limiting factor for transmission lines and that such information might be argued to constitute CEII.[195]

c. Commission Determination

85. As a preliminary matter, we clarify that, contrary to statements in EEI's request for clarification,[196] Order No. 881 requires transmission providers to post transmission line ratings and methodologies-related data to a password-protected section of their OASIS site *or* another password-protected website. Therefore, transmission providers have the discretion to post the required data to their OASIS site or an alternative password-protected website. We note, however, that the data posted to either a transmission provider's website or OASIS must be maintained such that users can view, download, and query data in standard formats, using standard protocols.[197] If the transmission provider chooses to post the data to its own website instead of OASIS, we clarify that users must be able to access the data in a manner that is comparable to if it were posted to OASIS and subject to OASIS access requirements.[198]

86. Consistent with these clarifications, we decline to establish further requirements regarding access to OASIS or to a password-protected website the transmission provider uses for compliance with Order No. 881 that would require demonstration of a business need or signing of a non-disclosure agreement. EEI has not explained why transmission providers should be able to restrict access to transmission line ratings and methodology data only to parties who have a ''business need'' and have executed a non-disclosure agreement. EEI's support for such restrictions is only a vague assertion that Order No. 881's requirements might not ''be sufficient to maintain confidentiality.''[199] We find this vague assertion inadequate for imposing the restrictions EEI describes, particularly since accessing much of the other transmission-related information on OASIS requires no such demonstration or signing of a non-disclosure agreement under the Commission's rules governing OASIS.

87. Conversely, we find that avoiding such restrictions maintains the benefits of transparency into transmission line ratings and methodologies that the Commission articulated in Order No. 881 and elsewhere in this order. In other words, we are not persuaded that any confidentiality benefits that would come from allowing the kind of restrictions EEI requests would outweigh the loss of transparency benefits gained by the Commission's requirements. Thus, we uphold Order No. 881's finding that requiring transmission line ratings and methodologies to be shared via OASIS or other password-protected website creates a measure of transparency needed to ensure just and reasonable wholesale rates.[200]

88. We deny EEI's request for clarification that transmission line ratings and methodologies constitute CEII, and clarify that Order No. 881 did not revise the Commission's existing CEII requirements.[201] The Commission's CEII regulations govern only ''the procedures for submitting, designating, handling, sharing, and disseminating [CEII] *submitted to or generated by the Commission.*''[202] Because the transmission line ratings and methodologies are neither generated by the Commission nor filed with the Commission—either under current rules or under the requirements of Order No. 881—such information would not be considered CEII under the Commission's CEII regulations.

3. The Role of Independent Market Monitors

a. Final Rule

89. In Order No. 881, the Commission required transmission owners to share their transmission line ratings for each period for which they are calculated and transmission line rating methodologies with their transmission providers and with market monitors in RTOs/ISOs.[203] The Commission found that requiring transmission owners to share transmission line ratings and methodologies with their transmission providers and, in RTOs/ISOs, market monitors, will help remedy unjust and unreasonable wholesale rates caused by

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[191] *Id.* P 336.

[192] EEI Request for Rehearing at 4.

[193] *Id.* at 15.

[194] *Id.*

[195] *Id.*

[196] *Id.*

[197] *See* 18 CFR 35.28(b)(12); *Pro Forma* OATT, attach. M, AAR Definition; *see also Pro Forma* OATT, attach. M, Obligations of the Transmission Provider (''Postings to OASIS or another password-protected website: The Transmission Provider must maintain on the password-protected section of its OASIS page or on another password-protected website a database of Transmission Line Ratings and Transmission Line Rating methodologies. . . . The database must be maintained such that users can view, download, and query data in standard formats, using standard protocols.'').

[198] *Open Access Same-Time Information System and Standards of Conduct,* Order No. 889, 61 FR 21737 (May 10, 1996), FERC Stats. & Regs. ¶ 31,035, at attach. § V.3 ''Information Access Requirements (1996) (cross-referenced at 75 FERC ¶ 61,078), *order on reh'g,* Order No. 889–A, 61 FR 21737 (Mar. 14, 1997), FERC Stats & Regs. ¶ 31,049 (cross-referenced at 78 FERC ¶ 61,221), *reh'g denied,* Order No. 889–B, 81 FERC ¶ 61,253 (1997), *aff'd in relevant part sub nom. Transmission Access Policy Study Grp.* v. *FERC,* 225 F.3d 667 (DC Cir. 2000).

[199] EEI Comments at 15.

[200] *See, e.g.,* Order No. 881, 177 FERC ¶ 61,179 at PP 11 (finding that the transparency reforms adopted in Order No. 881 ''will ensure that prices reflect the true cost of the wholesale service being provided and thereby are necessary to ensure just and reasonable wholesale rates''), 39 (finding existing wholesale rates unjust and unreasonable due to lack of transparency, specifically the failure to ''provide market participants information important to making cost-effective decisions'' and the possibility for ''transmission owners to submit inaccurate near-term transmission line ratings'' that ''do not accurately reflect the cost of the wholesale service being provided'').

[201] Under the Commission's CEII regulations, an entity may submit information to the Commission requesting that it be treated as CEII. 18 CFR 388.113 (2021).

[202] *Id.* (emphasis added).

[203] Order No. 881, 177 FERC ¶ 61,179 at P 330.

inaccurate transmission line ratings.[204] The Commission reiterated that it will continue to conduct reviews of transmission line ratings as a component of broader tariff compliance audits and that Order No. 881 does not change the auditing requirements or authorities of any entity.[205] The Commission noted that many commenters used the term ''audit'' to describe activities by market monitors and other entities that the Commission's rules do not define as auditing and noted that the Commission retains its authority to formally audit for compliance with OATTs and other Commission-jurisdictional rules.[206]

b. Request for Clarification

90. EEI requests that the Commission clarify that the role of the independent market monitor is not to ''second guess'' the information provided by the transmission provider.[207] EEI requests clarification that any review of transmission line ratings and/or methodologies does not expand the market monitor's audit authority over this information provided by the transmission owner.[208] EEI requests clarification that the market monitor's role is limited to ''verifying the accurate mechanical implementation of transmission line ratings calculations (*e.g.,* detecting corrupt data) and not related to the line ratings formulations or inputs thereto.'' [209] EEI claims that the role of market monitors is to identify noncompetitive outcomes resulting from market power or manipulative behavior. EEI argues that the market monitor should be independent of interests in market outcomes, should not interfere with market participants' management of their assets, and should not interfere with RTOs/ISOs' and transmission owners' operations of the bulk electric system.[210] EEI requests that the Commission clarify that the market monitor has no audit or enforcement authority related to the use of transmission line ratings and any impacts on reliable operations or market outcomes.[211]

c. Commission Determination

91. We grant EEI's request for clarification in part and deny in part. We clarify that nothing in Order No. 881 changes or expands the role or authority of market monitors or the auditing responsibilities of any entity.[212] However, we deny EEI's request for clarification on other matters. We expect that market monitors may use the transmission line rating information available to them in furtherance of their existing responsibilities, which are set forth in the Commission's regulations and the relevant tariffs of each RTO/ISO.[213]

D. Compliance

1. Final Rule

92. In Order No. 881, the Commission adopted a modified implementation schedule from that proposed in the NOPR. In particular, in the NOPR, the Commission proposed requiring AAR implementation on congested transmission lines within one year from the date of the compliance filing and, for all other transmission lines, implementation within two years from the date of the compliance filing.[214] In the final rule, the Commission required implementation of the requirements adopted in Order No. 881 no later than three years from the compliance filing due date. Based on comments submitted in response to the NOPR, [215] the Commission found that three years is consistent with the implementation schedule most commonly suggested by transmission owners for AAR implementation on priority transmission lines, and that three years should be sufficient time for transmission owners and transmission providers to implement changes to their processes and systems to comply with the requirements of Order No 881.[216]

2. Request for Rehearing

93. EEI seeks rehearing, arguing that the implementation schedule set forth in Order No. 881 was made without any evaluation of the number and types of transmission lines that would be implicated by the final rule.[217] EEI claims that, while some commenters may have opined that three years would be a sufficient amount of time to implement AARs, these comments were based on the NOPR proposal that would have required that AARs be implemented on historically congested transmission lines, not on all transmission lines.[218] EEI argues that the three-year implementation period does not consider the substantial increase in the number of transmission line ratings that the final rule requires transmission providers to compute as compared to the NOPR. In addition, EEI argues that the implementation timeframe does not consider or provide information on whether third-party vendors have the database infrastructure or the ability to develop the database infrastructure necessary to support the data requirements in the final rule. EEI contends that a longer implementation period would provide additional time for coordination, which would benefit transmission owners that have facilities in multiple states.[219]

94. Potomac Economics also requests rehearing, but argues that the Commission should require implementation of AARs and emergency ratings as soon as practicable rather than permitting transmission providers and transmission owners to wait three years to comply with these requirements.[220] Specifically, Potomac Economics contends that the Commission made a well-reasoned finding that failing to adjust transmission line ratings for changes in ambient air temperature and failing to utilize emergency ratings can lead to wholesale rates that are unjust and unreasonable, and should only be done if it were infeasible to require AARs more quickly than the three-year deadline established in the final rule. In particular, Potomac Economics requests that the Commission modify its proposed implementation schedule to require that AARs be implemented within one year of the final rule on a designated number of the most congested constraints that are not currently being adjusted.[221]

95. Potomac Economics also requests rehearing of the Commission's determination to require the use of emergency ratings on the same implementation timeframe as AARs. Potomac Economics states that, while there may be ''challenges'' for resources required to implement AARs, this is not generally true of emergency ratings, as they can be provided under most RTOs/ISOs' current systems with no significant modifications, arguing that emergency ratings are particularly important because the vast majority of real-time constraints are first-contingency constraints where emergency ratings are presumptively appropriate.[222] Potomac Economics argues that it is unreasonable for the

[204] *Id.* P 331.
[205] *Id.* P 334.
[206] *Id.* P 334 n.813.
[207] EEI Request for Rehearing at 3.
[208] *Id.* at 14.
[209] *Id.*
[210] *Id.*
[211] *Id.* at 14–15.
[212] Order No. 881, 177 FERC ¶ 61,179 at PP 333–34.
[213] 18 CFR 35.28(g)(3).
[214] NOPR, 173 FERC ¶ 61,165 at P 81.
[215] Order No. 881, 177 FERC ¶ 61,179 at P 361 n.870.
[216] *Id.* PP 360–361.
[217] EEI Request for Rehearing at 7–8.
[218] *Id.* at 8.
[219] *Id.*
[220] Potomac Economics Request for Rehearing at 5.
[221] *Id.* at 6–7.
[222] *Id.* at 7–8.

Commission not to require near-term implementation of fixed emergency ratings pending the implementation of AARs given that: (1) The failure to utilize emergency ratings on contingency constraints is a major contributor to unjust and unreasonable wholesale rates; (2) the information needed to provide unadjusted emergency ratings is readily available for most constraints; and (3) there are no dependencies between providing fixed seasonal emergency ratings and later adjusting such ratings for changes in ambient air temperatures. Potomac Economics contends that allowing the emergency ratings requirements to be suspended for up to three years will result in inflated congestion and curtailments of low-cost generation and is indisputably unreasonable, is unsupported by the record, and has not been reasonably justified or explained by the Commission. Potomac Economics requests that the Commission revise its implementation schedule to require near-term implementation of reliable emergency ratings in the real-time markets, day-ahead markets, and forward markets and in planning studies.[223]

3. Commission Determination

96. We sustain the Commission's determinations in Order No. 881 on this issue. As an initial matter, EEI mischaracterizes the NOPR proposal as one in which ''AARs would be implemented on congested lines, not all lines.'' [224] In fact, the NOPR proposed a staggered approach that would prioritize implementation on congested transmission lines (within one year from the date of the compliance filing for implementation of the proposed reforms to become effective) and require a longer timeline for implementation of AARs on all other transmission lines (within two years of the date of the compliance filing for implementation of the proposed reforms to become effective).[225] EEI acknowledged this in comments in response to the NOPR, that it ''agrees with a staggered approach, similar to the Commission's proposal'' but suggested that the Commission ''not require that companies deploy AARs on all transmission facilities.'' [226]

97. EEI suggests that the three-year implementation period does not consider the ''substantial increase in the number of ratings that the final rule requires to be computed,'' as compared to the NOPR, nor whether third-party vendors will be able to support the data requirements of Order No. 881.[227] Contrary to EEI's argument, the Commission did consider the requirements adopted in the final rule—as opposed to those in the NOPR—in setting the implementation timeline. The Commission determined that three years was a reasonable implementation timeline by considering the comments filed in response to the NOPR. Multiple commenters noted that one of the largest impediments to the NOPR's proposed two-year implementation timeline was the time needed to develop necessary software changes, which are largely one-time upgrades applicable to both congested and non-congested transmission lines.[228] In giving transmission providers more time to implement the requirements adopted in Order No. 881 than proposed in the NOPR, the Commission responded to commenters' justification for additional time to develop the software but balanced that with the fact that once the software is in place, the calculations are largely automated. Thus, the Commission's determination in setting the three-year implementation timeline accounted for potential implementation challenges of the more broadly applicable transmission line ratings requirements of the final rule.

98. As for third-party vendor availability, the Commission considered comments that raised these concerns in response to the NOPR.[229] Specifically, in the NOPR, the Commission proposed AAR requirements similar to those adopted in the final rule, and similarly explained that those requirements would necessitate that transmission providers implement an automated system in setting the implementation timeline.[230] For example, Arizona Public Service Company (APS) argued that ''adequate time is needed to develop the business requirements for the software vendors and that APS will have to work with multiple software vendors to comply'' [231] and then indicated that it agreed with EEI's assertion that ''between two to three years'' is needed to implement AARs on priority transmission lines.[232] As explained in Order No. 881 and above, we expect that the implementation burden is predominantly a one-time investment and that the burden of applying AARs to additional transmission lines is minimal.[233] Thus, in considering comments like APS's, the Commission determined that a three-year implementation timeline for all transmission lines—as opposed to just priority transmission lines—balances the need to implement the requirements adopted in Order No. 881 as soon as practicable to address unjust and unreasonable wholesale rates with the burden on transmission providers of complying with those requirements. In short, EEI fails to support the claims it makes about the potential for the data storage and sharing requirements to require additional time due to the need for third-party vendors beyond the extended three-year timeline adopted in the final rule. Thus, we are not persuaded that the additional requirements adopted in the final rule, as compared to the NOPR, necessitate further implementation delay.

99. Nor are we persuaded to adopt an earlier implementation, as requested by Potomac Economics. We find that a three-year implementation schedule provides a reasonable amount of time for transmission providers to implement the requirements of Order No. 881. As noted above, commenters raised concerns with the NOPR's proposed timeline, which was shorter than that adopted in the final rule. For example, MISO Transmission Owners, EEI, Southern Company, SCE, PacifiCorp, APS, ITC, and other commenters expressed concerns that it would be difficult to implement AARs on *any* transmission line within one year due to required operating and data system upgrades.[234] On the other hand, as the Commission explained in Order No. 881 and as we note above, three years is consistent with the implementation schedule most commonly suggested by transmission owners for AAR implementation on priority

[223] *Id.* at 8.

[224] EEI Request for Rehearing at 7.

[225] NOPR, 173 FERC ¶ 61,165 at P 81.

[226] EEI Comments at 6–7.

[227] EEI Request for Rehearing at 8.

[228] *See, e.g.,* Industrial Customers Comments at 22 (suggesting an implementation timeline of six months for congested transmission lines and one year for all others); PG&E Comments at 6 (suggesting a three-phase, five-year implementation timeline).

[229] *Compare* Order No. 881, 177 FERC ¶ 61,179 at P 119 (summarizing NYISO's comments that vendor availability for the software buildout necessary for calculating AARs for up to 10 days forward is unknown) *with id.* P 351 (explaining that NYISO requests flexibility for implementation and argues that the NOPR proposal does not give enough time for software changes to be developed). *Compare id.* P 354 (summarizing ITC's argument that the NOPR's proposed implementation timeline does not give enough time for software development or purchase from a vendor and analysis of the impact of the requirements on ITC's internal transmission line ratings database) *with id.* P 351 (stating that ITC argues that three years is needed to implement AARs on priority transmission lines).

[230] NOPR, 173 FERC ¶ 61,165 at P 95.

[231] APS Comments at 6.

[232] *Id.;* EEI Comments at 8; Order No. 881, 177 FERC ¶ 61,179 at PP 351, 353.

[233] Order No. 881, 177 FERC ¶ 61,179 at P 94.

[234] *Id.* PP 351–354.

transmission lines.[235] Potomac Economics addresses neither these operational and software concerns, nor the level of support for the three-year implementation schedule.

100. With regard to Potomac Economics' argument that the Commission should require implementation of fixed emergency ratings as soon as practicable, we find that the three-year implementation schedule is consistent with the implementation schedule most commonly suggested by transmission owners for AAR implementation on priority transmission lines,[236] and both the Commission and commenters explained that the availability of emergency ratings will need to be factored into ATC calculations.[237] Potomac Economics has not demonstrated that the implementation of emergency ratings on a faster timeline is feasible, particularly in the non-RTO/ISO regions and particularly in light of the challenges associated with updating ATC calculations articulated by commenters.[238] Moreover, as a matter of policy, there are administrative efficiencies to requiring implementation of all the requirements adopted in Order No. 881 on the same timeline. Specifically, by maintaining a single implementation timeline, the implementation burdens are lessened in that all transmission line rating recalculations must only be done once. In contrast, Potomac Economics' suggestion would require the calculation of seasonal emergency ratings followed by a separate calculation of emergency ratings to comply with the AAR requirements for the same transmission line. Thus, requiring implementation of all the requirements adopted in Order No. 881 on the same timeline is appropriate given the interrelationship between the AAR requirements, the emergency ratings requirements, and the requirement that AARs also be calculated for ''uniquely determined emergency ratings.'' [239] Therefore, as explained above, we sustain the findings in the final rule that justify a three-year implementation timeline for the other requirements of Order No. 881 and believe it appropriate to include the emergency ratings requirements in the same timeline.

[235] *Id.* P 361 (citing comments in support of a three-year implementation schedule).

[236] *Id.* P 361 (citing EEI Comments at 18; NRECA/LPPC Comments at 28–29; MISO Transmission Owners Comments at 22–23; SCE Comments at 2; SDG&E Comments at 1–2; APS Comments at 10; WFEC Comments at 1; Southern Company Comments at 6–7; ITC Comments at 5; LADWP Comments at 8–9).

[237] *Id.* PP 293, 296.

[238] *Id.* P 59 (citing BPA Comments at 3–4; PacifiCorp Comments at 2; Imperial Irrigation District Comments at 5–6; EEI Comments at 10–11; CAISO Comments at 10).

[239] *Id.* P 305.

E. Other Issues

101. ATC requests clarification that its current seasonal line ratings methodology meets the intent of Order No. 881 by providing what it characterizes as ''four seasons of accurate, science-based weather parameters'' and that its current AAR approach satisfies the requirements of Order No. 881.[240]

102. In response to ATC's request for clarification, we find that the appropriate proceeding for the Commission to make such a determination is through transmission providers' Order No. 881 compliance filings. As explained in Order No. 881, each transmission provider must submit a compliance filing within 120 days of the effective date of the final rule revising their OATT to incorporate *pro forma* OATT Attachment M.[241] The Commission acknowledged that ''some public utility transmission providers may have provisions in their existing *pro forma* OATTs or other document(s) subject to the Commission's jurisdiction that the Commission has deemed to be consistent with or superior to the *pro forma* OATT.'' [242] Where Order No. 881 modifies these provisions, ''transmission providers must either comply with the requirements adopted in this final rule or demonstrate that these previously approved variations continue to be consistent with or superior to the *pro forma* OATT, as modified by this final rule.'' [243] The compliance filing required by Order No. 881 is the proper vehicle for presenting this evidence to the Commission.

III. Information Collection Statement

103. The burden estimates have not changed from the final rule.

IV. Regulatory Flexibility Act Certification

104. The Regulatory Flexibility Act of 1980 (RFA) [244] generally requires a description and analysis of final rules that will have significant economic impact on a substantial number of small entities. Pursuant to section 605(b) of the RFA, we still conclude that the final rule will not have a significant economic impact on a substantial number of small entities.

[240] ATC Request for Clarification at 1.

[241] Order No. 881, 177 FERC ¶ 61,179 at P 12.

[242] *Id.* P 363; *see* 18 CFR 35.28(c)(1)(vi).

[243] Order No. 881, 177 FERC ¶ 61,179 at 363.

[244] 5 U.S.C. 601–612.

V. Document Availability

105. In addition to publishing the full text of this document in the **Federal Register**, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the internet through FERC's Home Page (*http://www.ferc.gov*) and in FERC's Public Reference Room during normal business hours (8:30 a.m. to 5:00 p.m. Eastern time) at 888 First Street NE, Room 2A, Washington DC 20426.

106. From FERC's Home Page on the internet, this information is available on eLibrary. The full text of this document is available on eLibrary in PDF and Microsoft Word format for viewing, printing, and/or downloading. To access this document in eLibrary, type the docket number excluding the last three digits of this document in the docket number field.

107. User assistance is available for eLibrary and the FERC's website during normal business hours from FERC Online Support at 202–502–6652 (toll free at 1–866–208–3676) or email at *ferconlinesupport@ferc.gov,* or the Public Reference Room at (202) 502–8371, TTY (202) 502–8659. Email the Public Reference Room at *public.referenceroom@ferc.gov.*

VI. Effective Date

108. The effective date of the document published on January 13, 2022 (87 FR 2244), is confirmed: March 14, 2022.

By the Commission.

Issued: May 19, 2022.

Debbie-Anne A. Reese,

Deputy Secretary.

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DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

18 CFR Part 375

[Docket No. RM22–15–000; Order No. 883]

Certification of Uncontested Settlements by Settlement Judges

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission (Commission) is revising its delegation of authority regulations to authorize the Chief